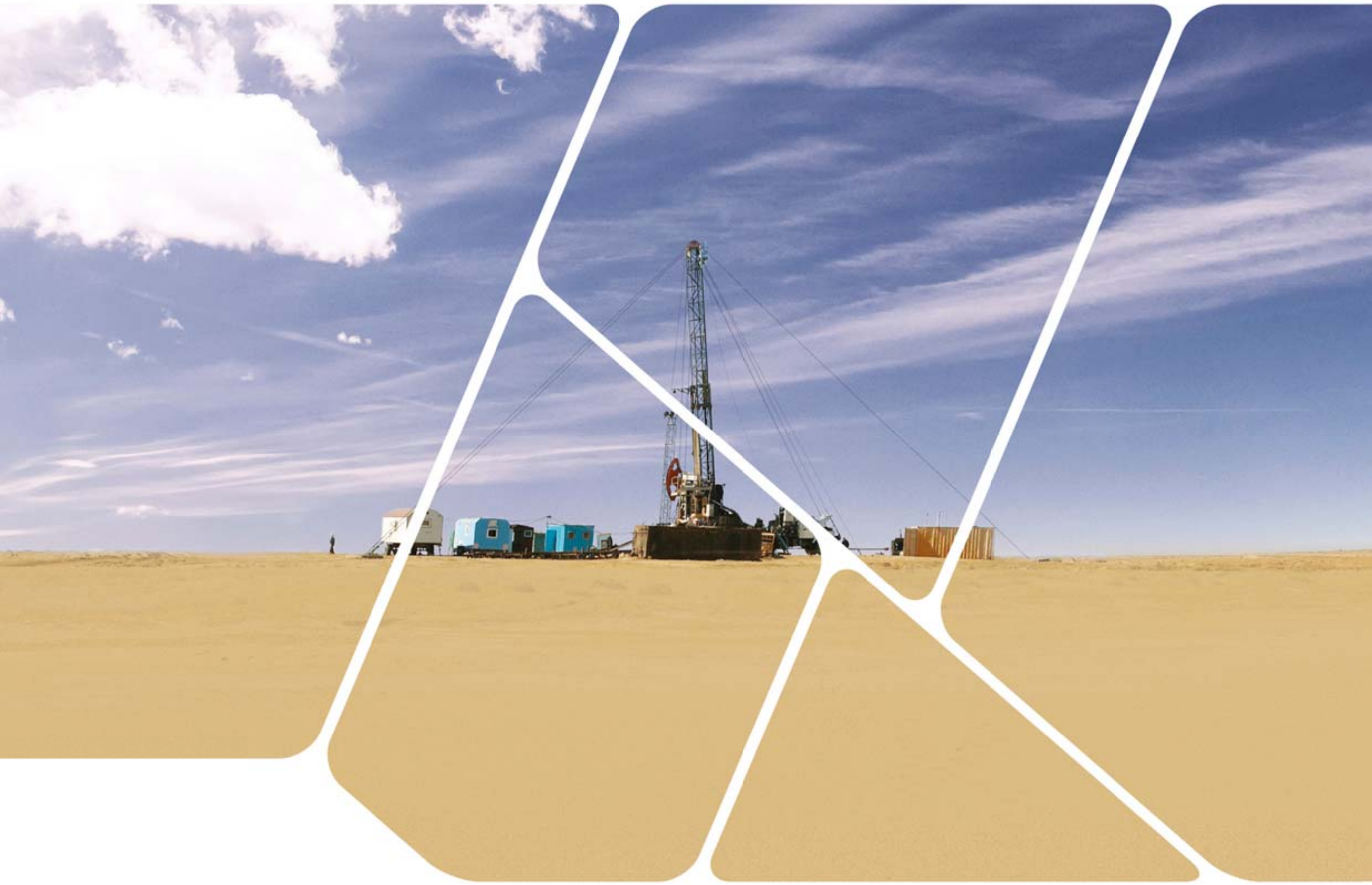


W3 : Completion et performance des puits

Formation certifiante en Management de la chaine de valeur de l'EP et Ingénierie pétrolière – *Du 04 Décembre au 08 Décembre 2016*

Well Productivity & Wellbore Interface

PPLCTE

IFP Training

Summary

- **Well completion**
  - Concerned area
  - Main factors influencing completion design
  - Main types of completion configuration
- **About fluids in reservoir**
- **Overall approach of the well flow potential**
- **Main phases in completion**
- **Reservoir-Wellbore Interface**
- **Artificial Lift**
- **Well servicing**
- **Appendix: Answers to exercises**

Well completion

IFP Training

Sommaire

- Concerned area
- Completion design
- Main types of completion configuration

Concerned area

Well completion: Concerned area

To "complete" a well:

- The hole being made by a driller
- To put it in production
- Taking into account reservoir conditions

$\Rightarrow$ **Well completion:**

- Crossroad between: - drilling
  - reservoir engineering
  - production

Well completion: Concerned area

= **Make the well produce for the first time:**

- Drilling in the producing formation
- Connecting the pay-zone and the borehole
- Treating the pay-zone
- Equipping the well
- Putting the well on stream
- Assessing the well

} **RWI (reservoir-wellbore interface)**

\+ **Operations on the well at a later date:**

- Measurement
- Maintenance
- Workover

Well completion: Concerned area

Greatly influenced by:

- The way the well has been designed and drilled
- Production problems the reservoir might cause

⇒ **Work in close collaboration with:**

- The driller
- The reservoir engineer
- The production staff

Main factors influencing completion design

Parameters related to well purpose:

Exploration well

- **Prime objective:**
  - To prove the presence of oil or/and gas:
    - Nature and characteristics of the fluids in place in the reservoir (including the water)
- **Other objective:**
  - To know characteristics of the pay-zone:
    - Initial pressure and temperature
    - Approximate permeability and productivity
- **Means:**
  - Wireline logging
  - Test string

⇒Decision to develop or not
Well suspended or abandoned

Parameters related to well purpose (cont.):

Confirmation well (or appraisal or delineation)

- **Objectives:**
  - Refine the results from the exploration well:
    - Strictly representative sample
    - Pressure, permeability and well productivity
  - Determination of the off wellbore reservoir characteristics:
    - Off wellbore permeability
    - Heterogeneity, discontinuity, faults
    - Reservoir boundaries, possible water drive
- **Means: well testing**
  - Designed with the help of knowledge from exploration well
  - Usually more complete

  ⇒ Longer duration for the testing

Parameters related to well purpose (cont.):

Development well

- **Types of development wells:**
  - Production wells
  - Injection wells
  - (Observation wells)
- **Objective (depending on the well type):**
  - To produce the reservoir
  - To inject fluid for pressure maintenance or sweeping effect
  - (run some measurement tools)
  - ⇒ Flow potential
- **Note: importance of testing to:**
  - Asses the condition of the well
  - Obtain further information about the reservoir

Parameters related to environment

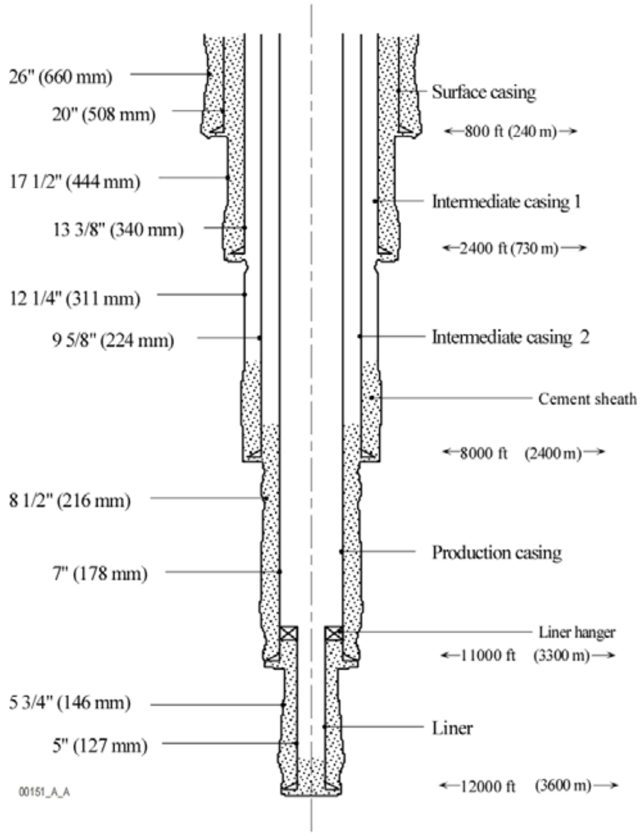
- Area, Country
- Well location
- ……………

⇒ Constraints

Parameters related to drilling

- Drilling rig used
- Well profile
- Drilling and casing program*
- Drilling in the pay-zone(s) & drilling fluid:
  - Formation damage ⇒ prevention
    restoration
  - Others considerations
- Cementing the production casing

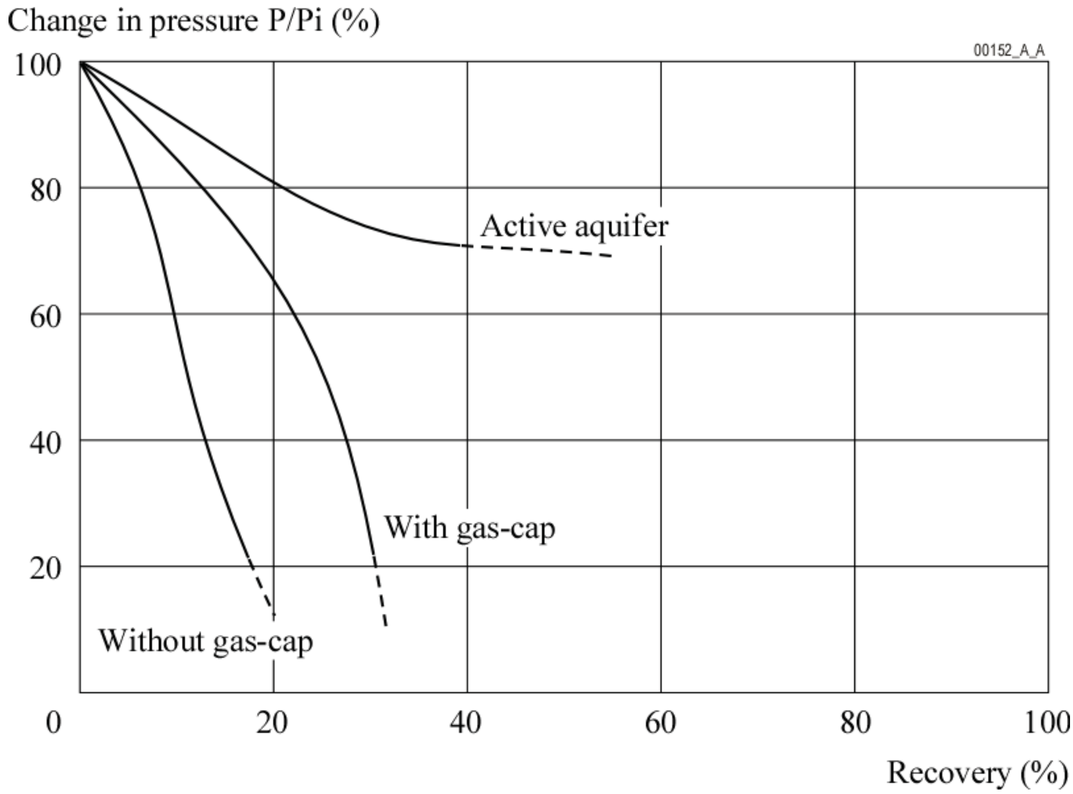
Available diameters according to the drilling and casing program



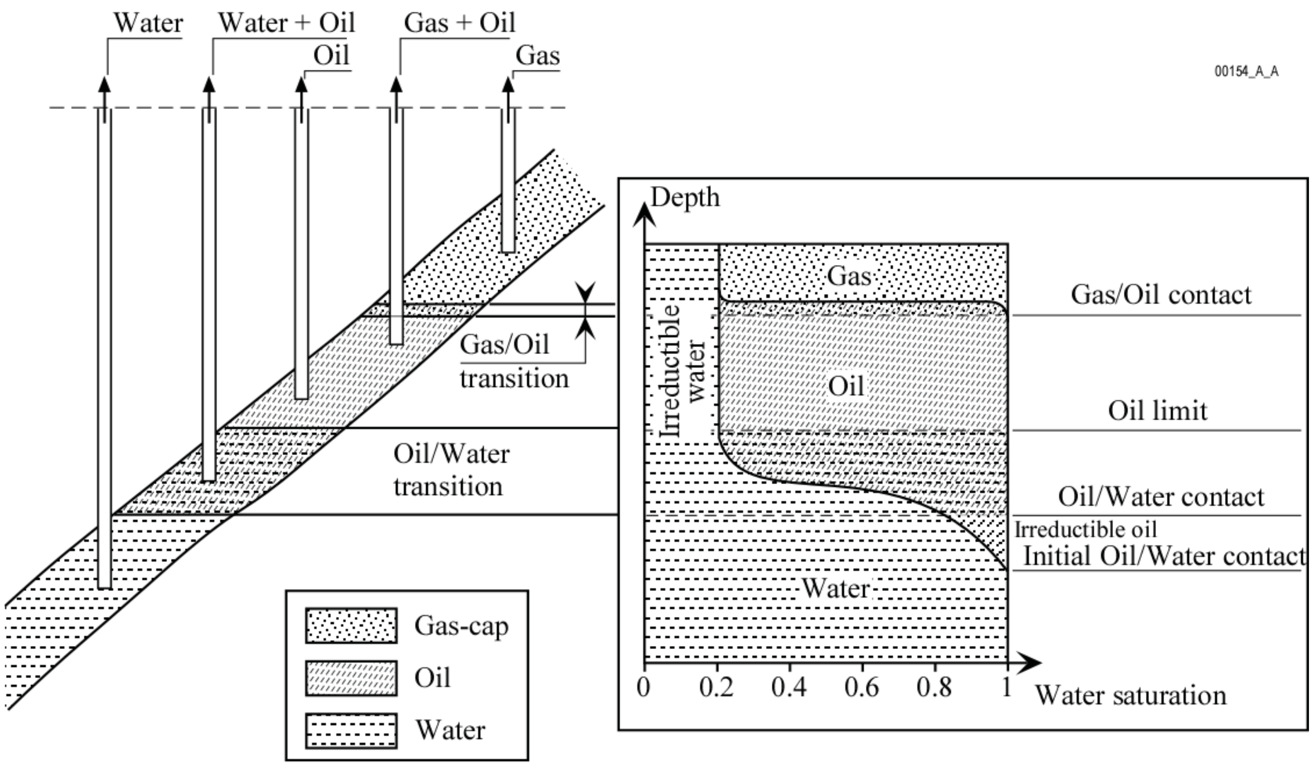
Parameters related to reservoir

- **Reservoir pressure and its change***
- **Interfaces between fluids and their changes***
- **Number of levels to be produced**
- **Rock characteristics & Fluid type**
- **Production profile & Number of wells required**

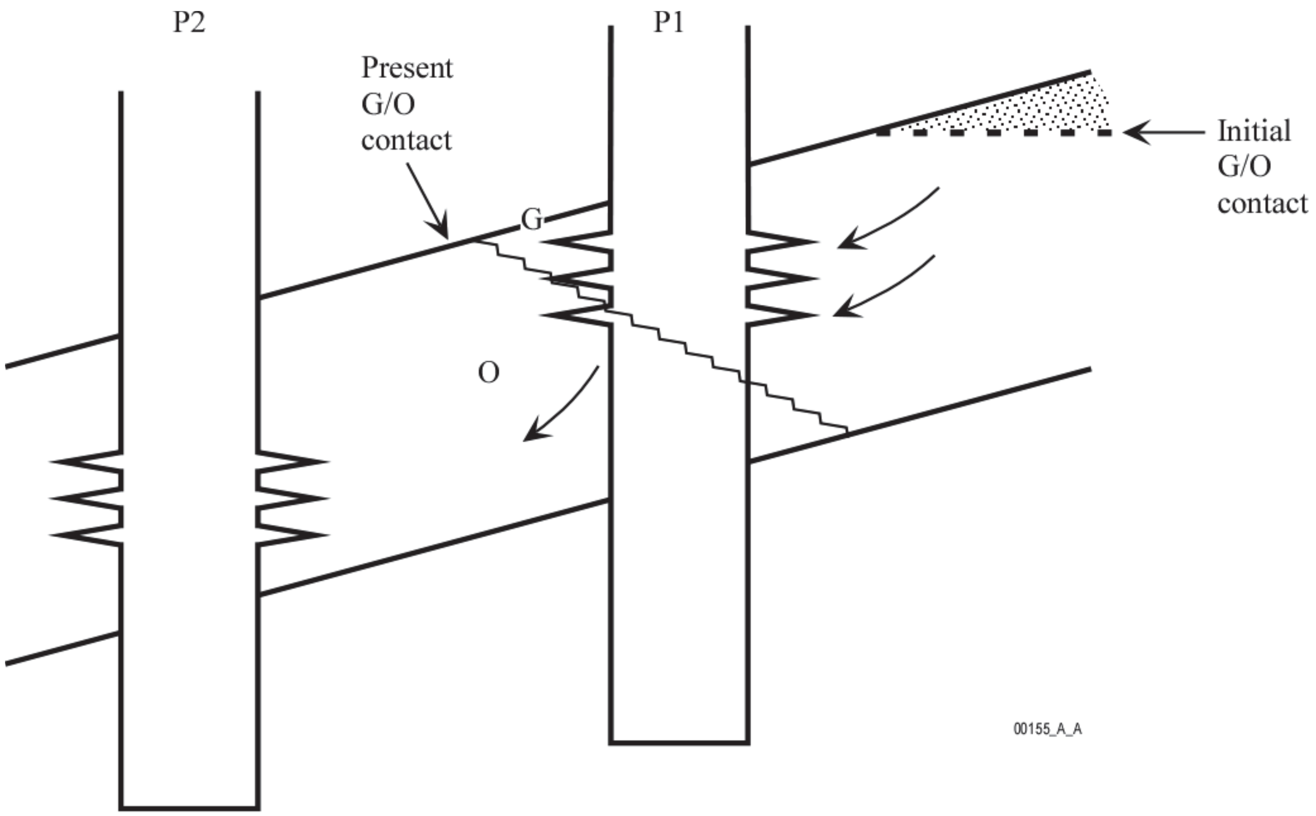
Change in the reservoir pressure versus cumulative production



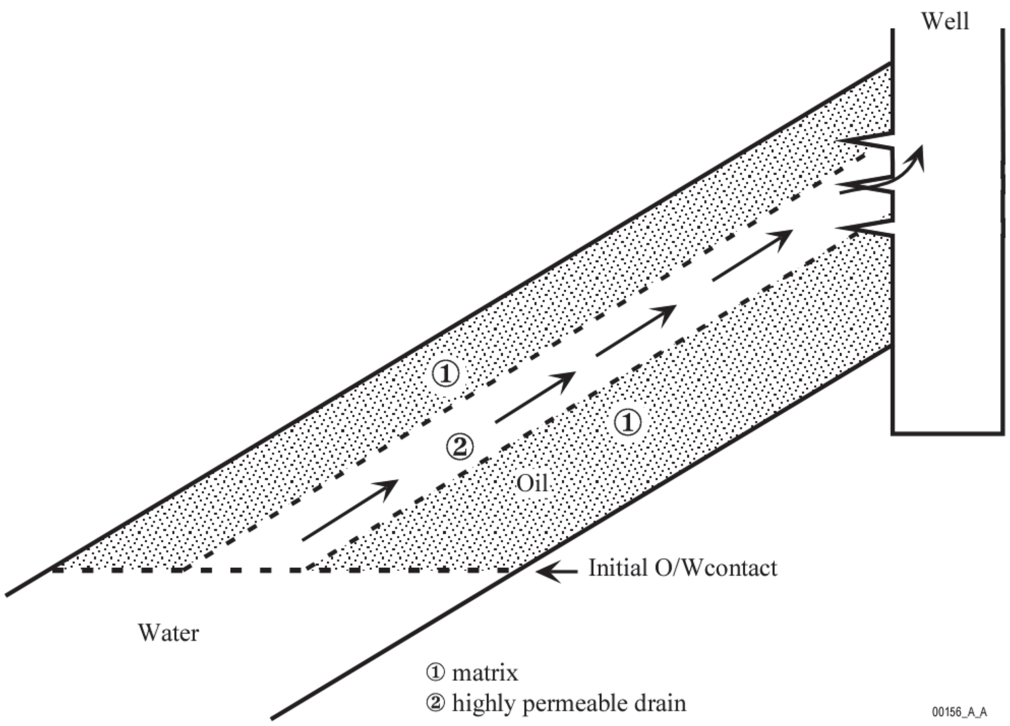
Fluids distribution in a homogenous reservoir



Interface change with cumulative production



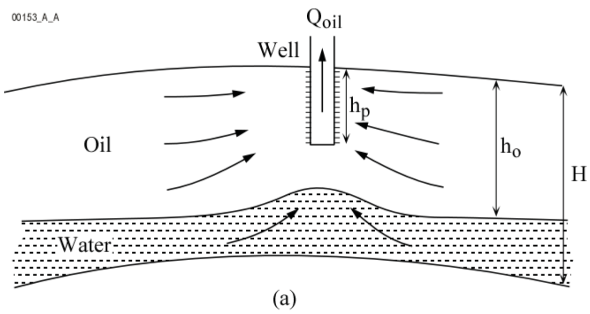
Influence of a highly permeable drain on a W/O contact

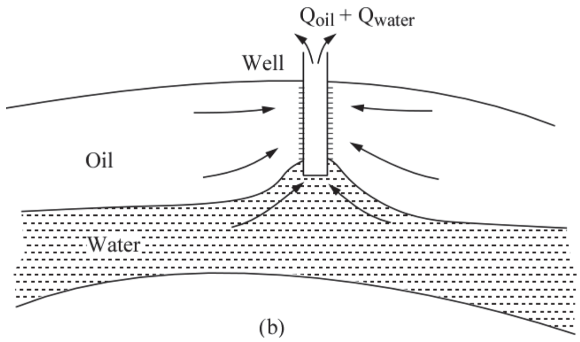


Coning

a) Stable cone

b) Water encroachment in well





H: **Pay zone thickness**

h_o: **Thickness occupied by oil**

h_p: **Well penetration**

Parameters related to production

- Safety
- Flowing well or artificial lift
- Operating conditions
- Anticipated measurement, maintenance or workover operations

Parameters related to completion technique

- **Interdependent choices**
- **Function of the other parameters**

=> Compromise

Completion design

- **From main purposes decided by:**
  - Company operation management
  - Reservoir engineering department
- **As:**

  For exploration or appraisal well:
  - Level to be tested
  - Type of test
  - ...

  For development well:
  - Level(s) to be produced
  - Production profile
  - ...

Completion design (cont.)

- **The problem is to design the best possible completion in order to:**
  - Optimise productivity (or injectivity)
  - Ensure reliability and safety
  - Optimise equipment lifetime
  - Be able to adapt the well to future change
  - Minimise costs (investment, operating, workover)

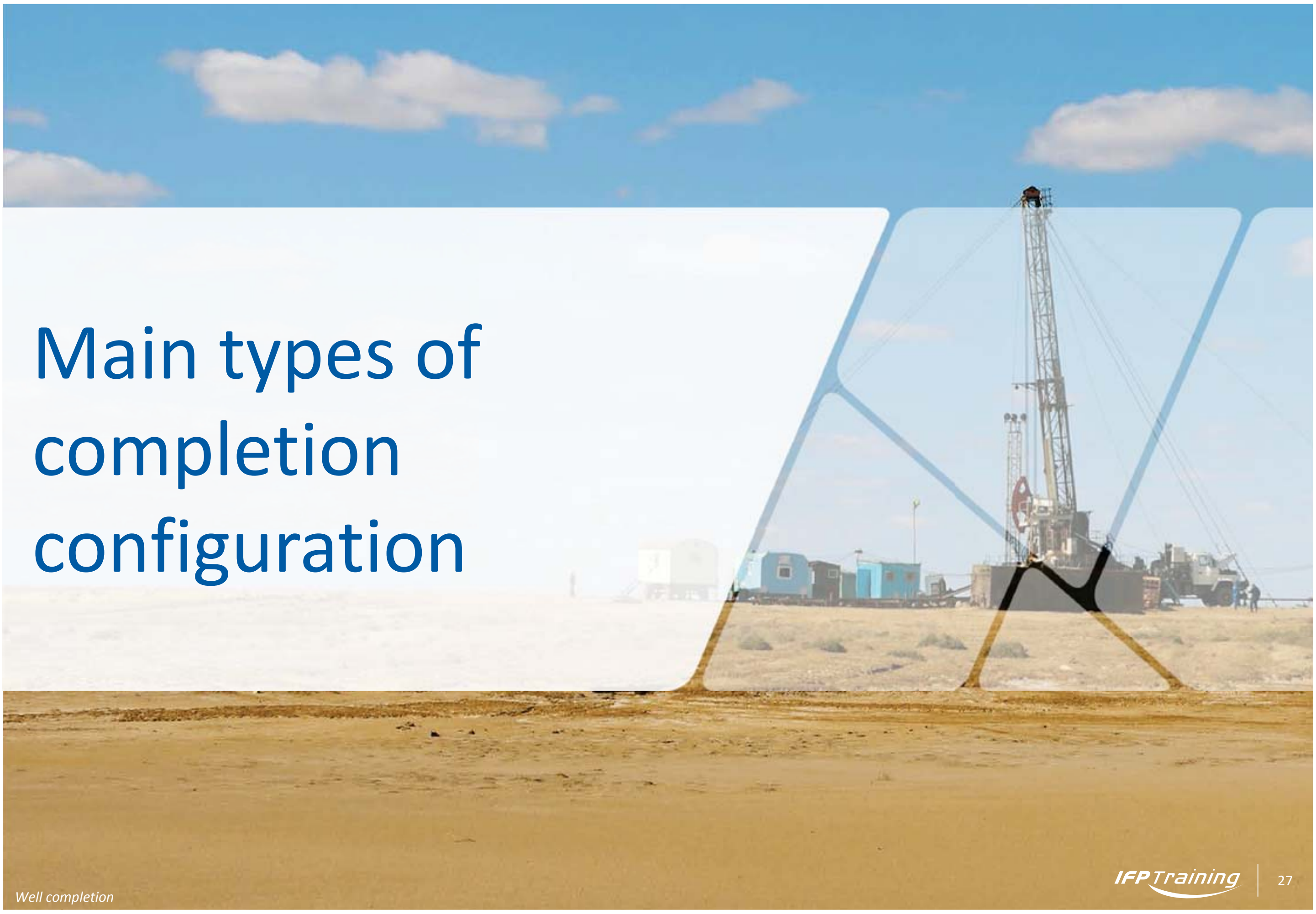
  ⇒ Compromise or modified purposes

Completion design (cont.)

- **Main constraints**
  - Local constraints
  - Effluent characteristics
  - Reservoir characteristics
  - Number of producing formations
  - Available diameter, borehole profile
  - Necessity for treatment operations
  - Necessity to maintain reservoir pressure, for artificial lifting
  - Later operations

Completion design (cont.)

- **Importance of data gathering**
- **But the job is not easy since data are:**
  - Very numerous
  - Sometimes tardily known
  - Sometimes contradictory
  - Negociable or not



Main types of completion configuration

Summary

Main types of completion configuration

- Preamble
- Basic requirements
- Configuration of the reservoir-wellbore interface
- Configuration of production string(s)

Main parameters for completion design (reminder)

- Type of well:
  - Exploration
  - Confirmation or appraisal (or delineation)
  - Development
- Well purpose:
  - Production
  - Injection
  - Observation
- Production way:
  - Naturally flowing well
  - Artificial lift
- Interface between fluids
- Number of zones to be produced:
  - (all together)
  - separately
- Anticipated measurement, maintenance or workover operations

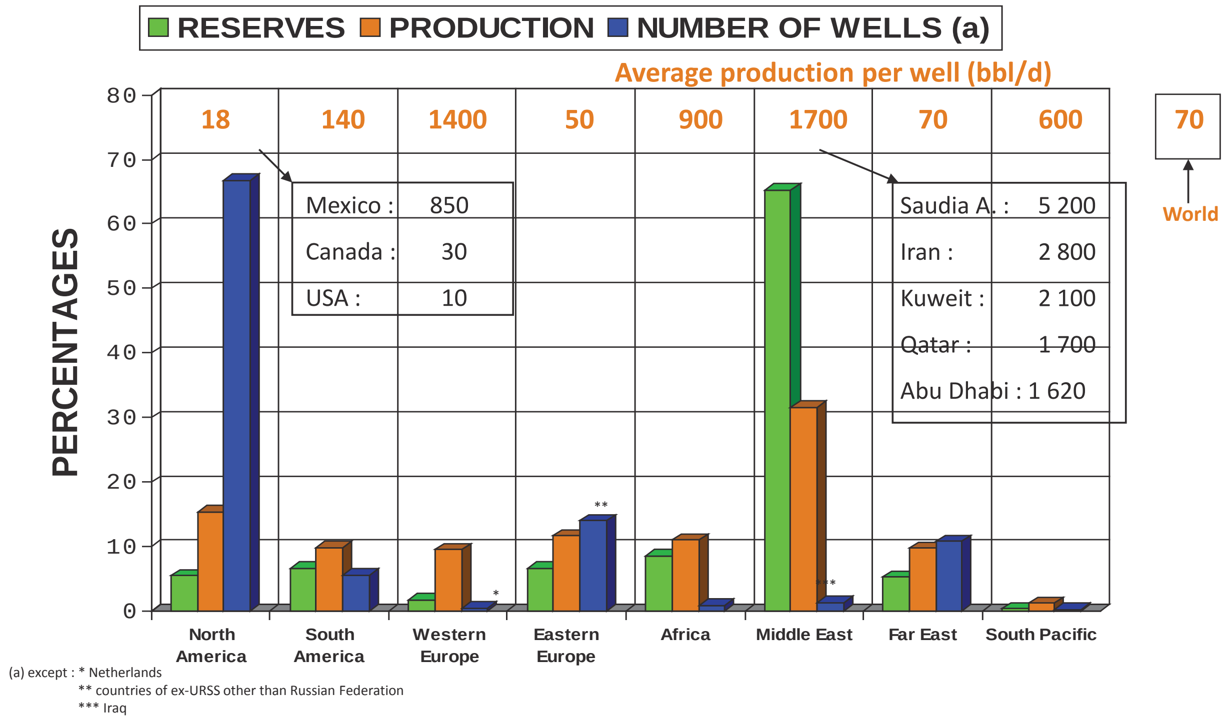
Objective

- To choose the best suited configuration:
  - Greatest possible flow potential
  - At the lowest cost

  ⇒ Compromise
- Compromise taking into account:
  - Costs:
    - Capital expenditure (CAPEX)
    - Operating expenditure (OPEX)
  - Relativity
  - Anticipation

  and also:
  - Flowrate per well*
  - Risk:
    - In relation with the flowrate
    - In relation with safety
  - Cultural factor

Statistics on oil production (end of 2000)
(from World Oil august 2001)



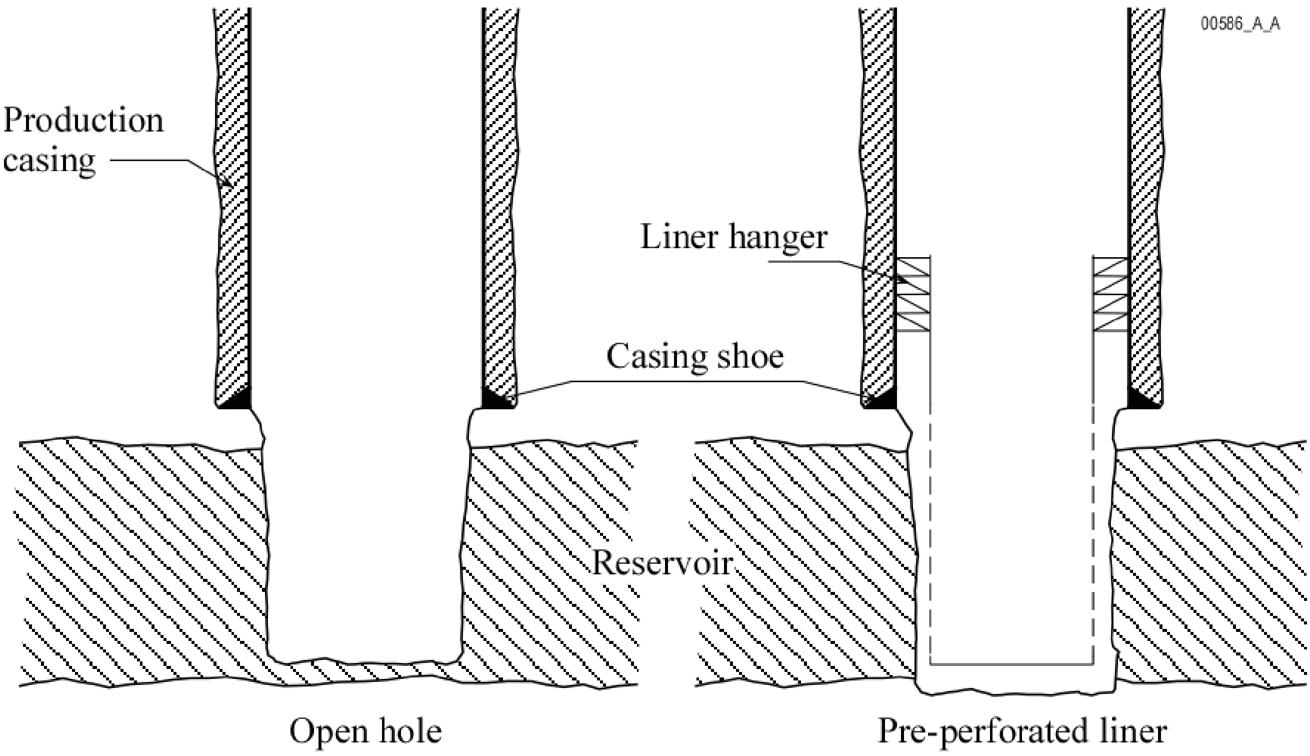
Basic requirements

- Borehole wall stability
- Selectivity of fluid or pay zone(s)
  (including selectivity of the zone to be treated, if any, and treatment efficiency)
- Minimal restrictions along flow path, so well flow potential optimisation
- Well safety
- Flow adjustment
- Operations to be performed at a later date (measurement, maintenance, etc.) without having to resort to workover
- Easy workover when necessary

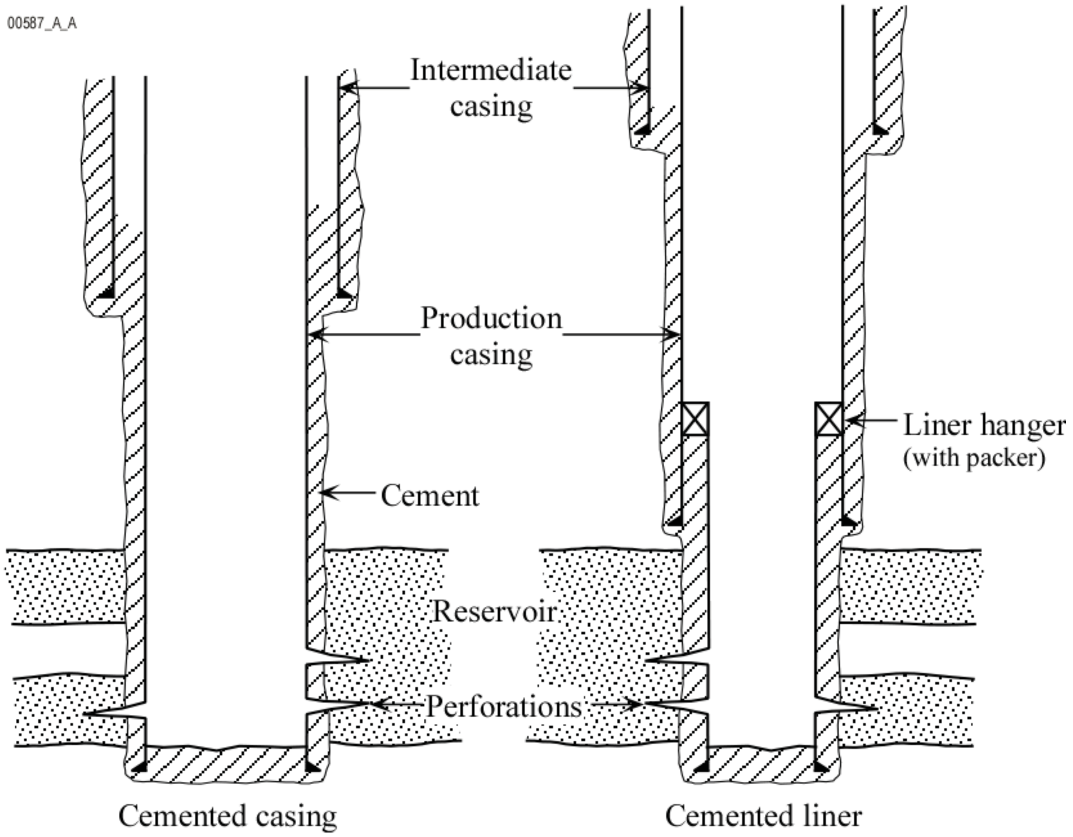
Configuration of the reservoir-wellbore interface

- **Choice between:**
  - Open hole*
  - Cased hole*
- **Take also into account (if the problem arises):**
  - Perforation method
  - Sand control method
  - Stimulation method
  - "Conventional" drain (vertical or slanted) or horizontal drain

Open hole completion



Cased hole completion

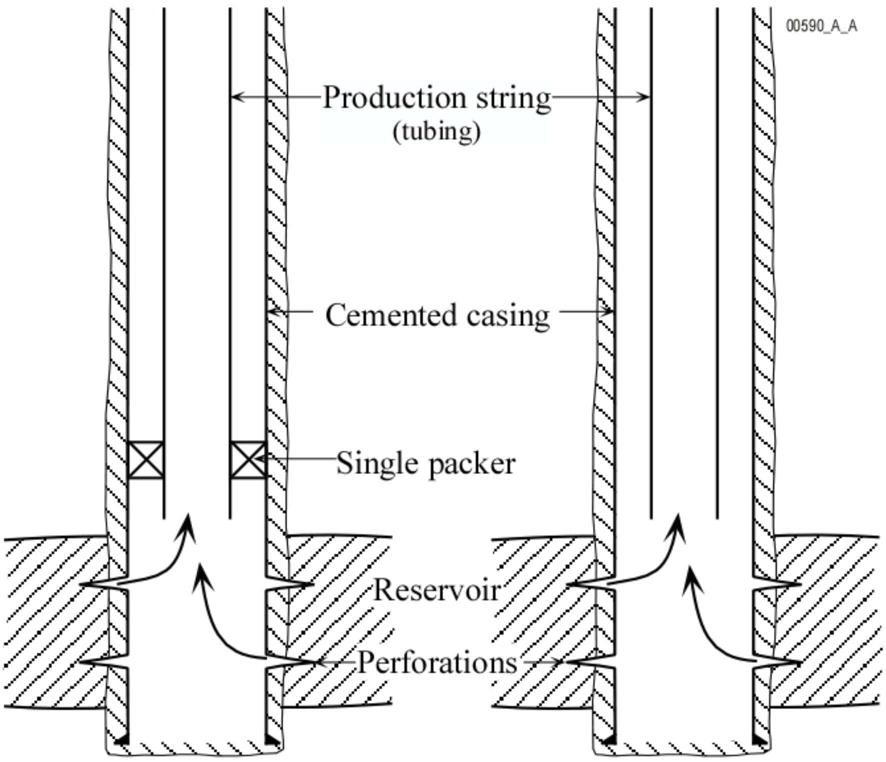


Configuration of production string(s)

Configuration of production string(s)

- **Conventional completion*:**
  - Single zone
  - Multi zones:
    - Parallel dual string
    - Tubing - annulus
    - Alternate selective
- **Tubingless completions*:**
  - Single zone
  - Multi zones
- **Miniaturised completions**
- **Example of equipment for a naturally flowing well (single zone completion)***

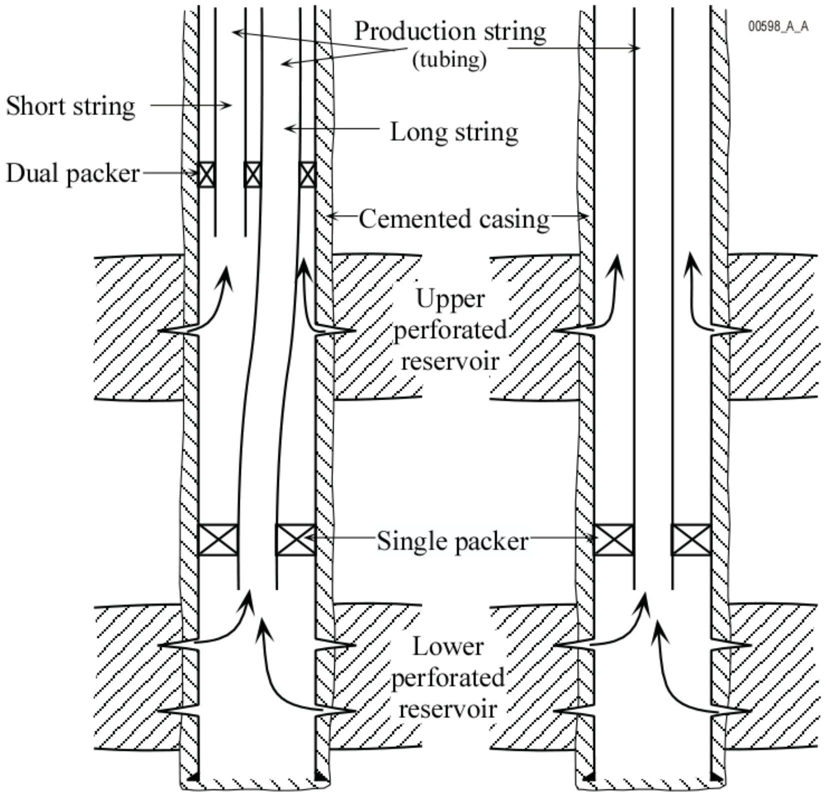
Single zone completion



With tubing and packer

With tubing alone

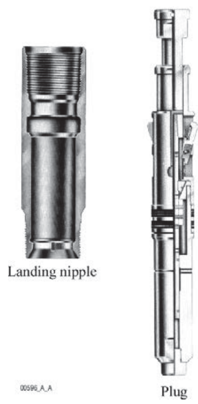
Multi zones completion

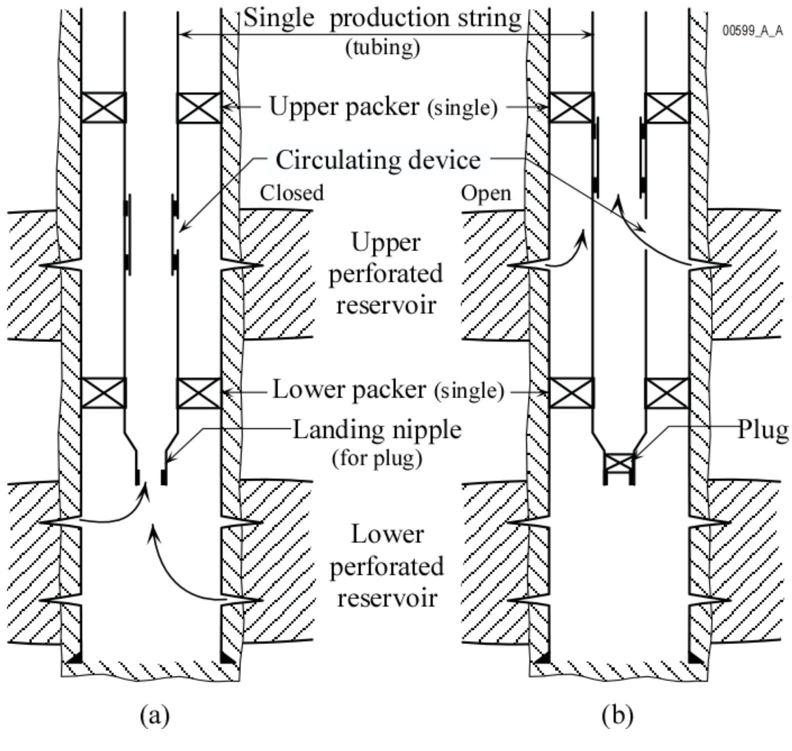


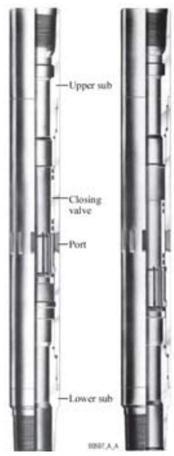
a: Parallel dual tubing strings **b: Tubing - annulus completion**

Multi zones completion (cont.)

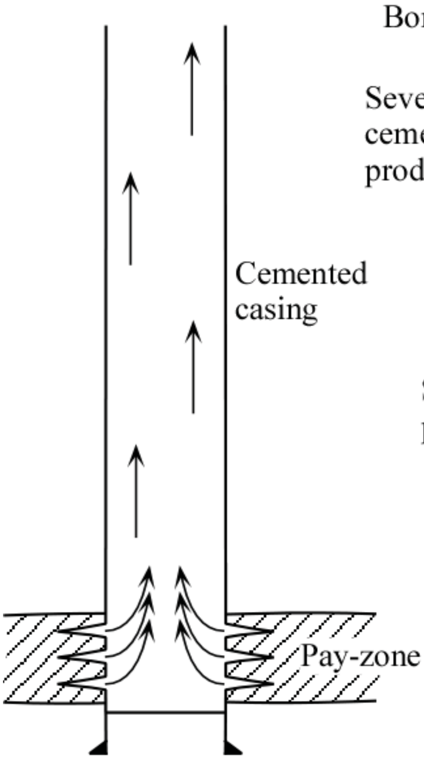
c: Alternate selective completion



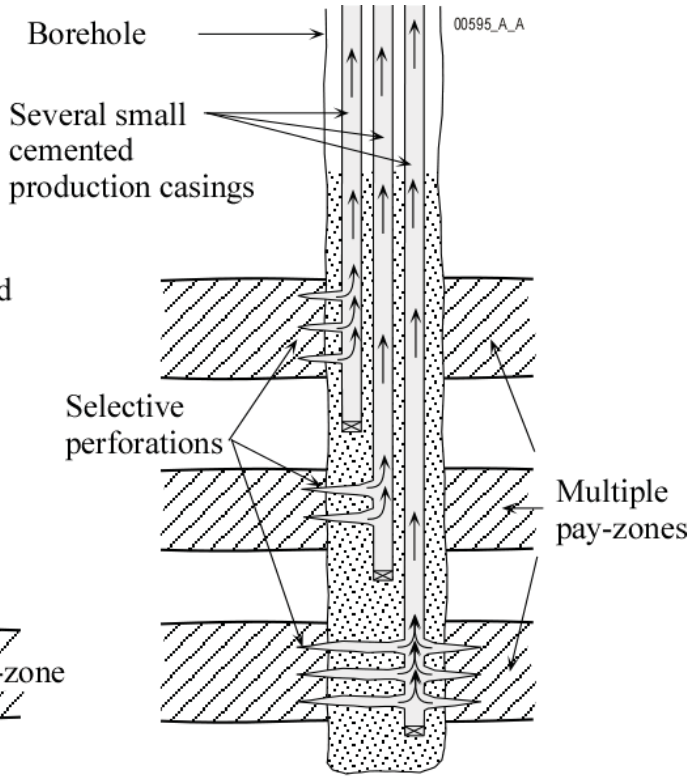




Tubingless completion

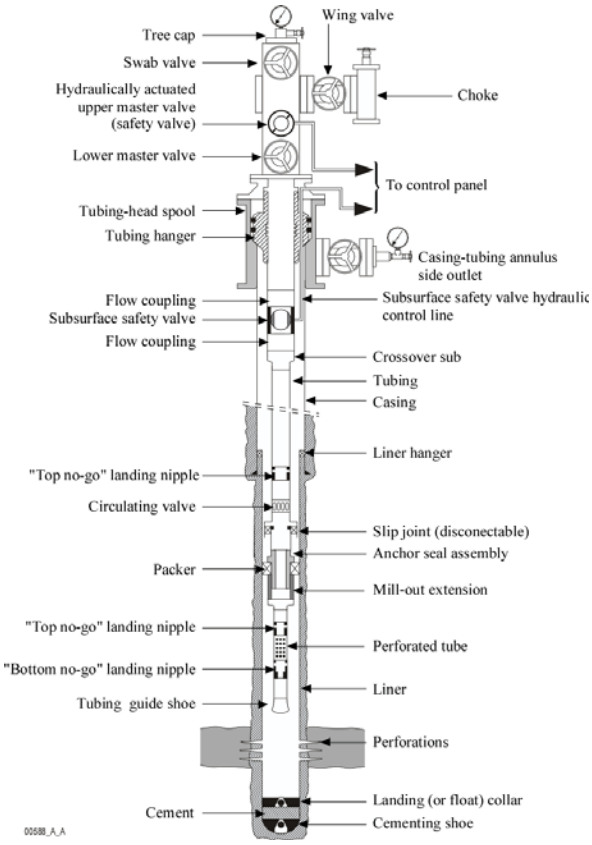


a: Single zone



b: Multi zones

Synthesis: example of equipment for a naturally flowing well



Main phases in completion

Initial completion

(case of a cased hole configuration)

- Checking the cement job
- Remedial cementing (if needed)
- Re-establishing the pay zone-borehole communication
- Well testing
- Treating the pay zone :
  - Stimulation (acidizing, fracturing)
  - Sand control
- Equipment installation
- Putting the well on stream & Assessing performance
- Moving the rig

Operations to be performed at a later date

- Measurements
- Maintenance
- Workover
- Abandonment

About fluids in reservoir

Summary

- Fluids flow and repartition in the reservoir
- Characterisation of the fluids in the reservoir

Fluids flow and repartition in the reservoir

key parameters

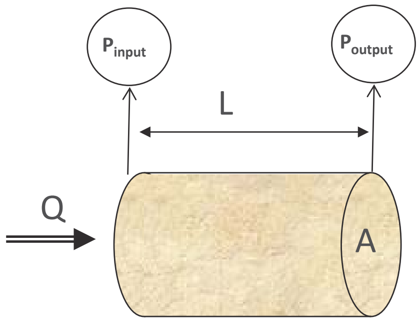
Absolute permeability (k_a) & Darcy law

Definition:

The permeability k_a characterises the fluid flow trough a given porous media, the rock containing only this fluid

Quantification – Darcy's law:

$$Q = \frac{k_a}{\mu} \times A \times \frac{(P_{input} - P_{output})}{L}$$



k_a is directly related to the size of the connection between the pores (unit: Darcy or milliDarcy - mD)

μ is the viscosity of the flowing fluid (unit: centipoise - cP)

Careful, permeability is not directly related to porosity:

Example: pumice stone has a very high porosity but no permeability as the pores are not connected together

Saturation

Definition:

S = Relative amount of fluids inside the pores

S_w = Water volume / Total pore volume = water saturation

S_o = Oil volume / Total pore volume = oil saturation

S_g = Gas volume / Total pore volume = gas saturation

$$S_w + S_o + S_g = 1$$

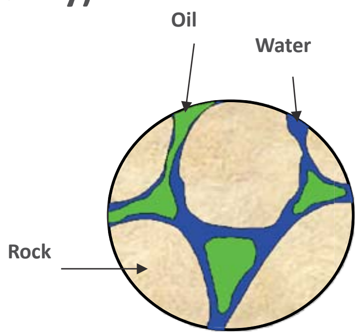
Linked to the surface properties of the rock (wettability)

Practical cases:

Water/Oil: Water is often the wetting fluid

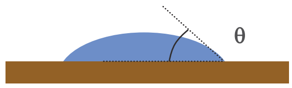
Oil/Gas: Oil is the wetting fluid

Water/Gas: Water is always the wetting fluid



Wettability: several experiments

The table is air wet (grease) $\theta > 90°$ | Undefined wettability $\theta = 90°$ | The table is water wet (potato) $\theta < 90°$



Wings of a butterfly is never wet by water

Modification of the wettability by a surface tensio-agent

Consequences: It will be difficult to wash the oil during a water flooding

Relative permeability concept

Definition of effective permeability (k_f) relative permeability (k_{rf}) :

Extension of Darcy's law to each fluid with $k_{rf} = k_f / k_a$:

$$Q_{oil} = \frac{k_a \times k_{r.oil}}{\mu_{oil}} \times A \times \frac{\left(P^{oil}_{input} - P^{oil}_{output}\right)}{L}$$

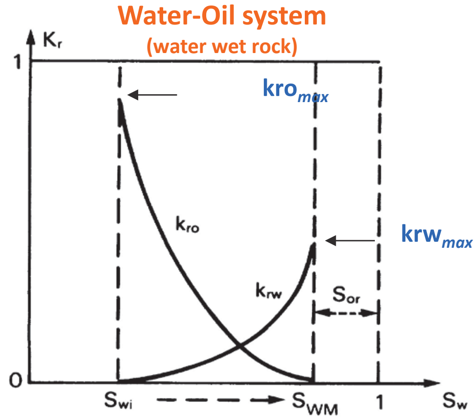
Oil, water and gas permeability

Use of the relative permeability*

Irreducible saturations:

- S_{wi} : irreducible water saturation
- S_{or} : residual oil saturation
- S_{gc} : critical gas saturation

Water-Oil system (water wet rock)



Mobility of the fluids at their maximum saturations

Oil: $M_o = \frac{k_a \times k_{ro.max}}{\mu_o}$

Water: $M_w = \frac{k_a \times k_{rw.max}}{\mu_w}$

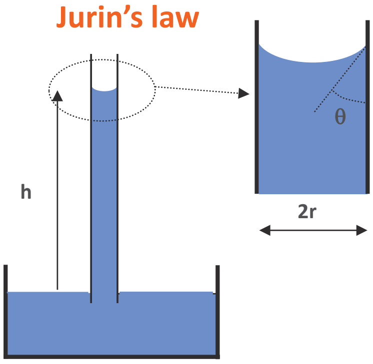
Mobility ratio: $R_{w/o} = M_w / M_o = \frac{k_{rw.max}}{\mu_w} \times \frac{\mu_o}{k_{ro.max}}$

Viscosity (μ_f) & Mobility (M_f) of the different fluids

- **Viscosity :**
  - μ_w : From 0.3 cP to 1 cP
    Mainly function of temperature
    (note: μ_w = 1 cP at 20°C and 1 atm)
  - μ_o : 0.3 cP to several hundred cP (or more)
    Mainly function of:
    - oil composition
    - temperature
  - μ_g: From 0.01 cP to 0.03 cP (or more)
    Mainly function of pressure
- **Mobility of the different fluids (for $S_g > S_{gc}$, $S_w > S_{wi}$ & $S_o > S_{or}$):**
  - $M_g >> M_w \approx$ or $>$ or $>> M_o$
    (depending on the oil viscosity)

Capillarity

Jurin's law

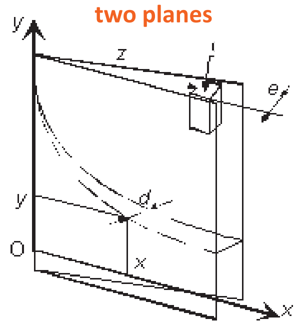


$$h = \frac{2\sigma \times \cos\theta}{\rho g r}$$

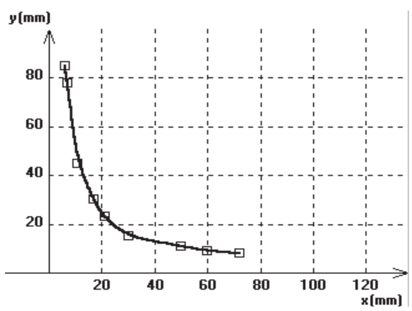
σ: surface tension
θ: contact angle
r: radius of the capillary tube
ρ: water density

Capillary rise in tubes

Capillary rise between two planes

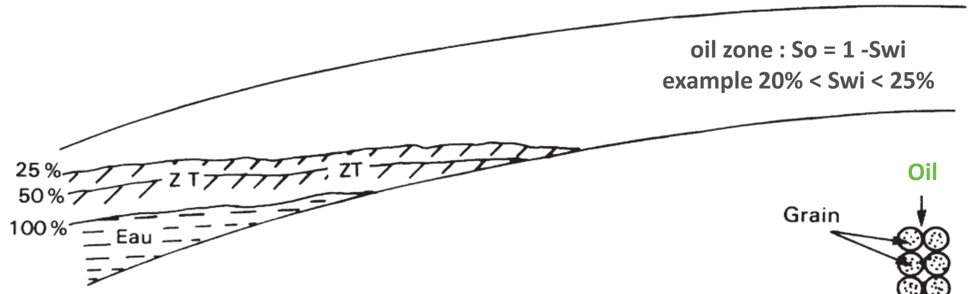


Capillary rise curve



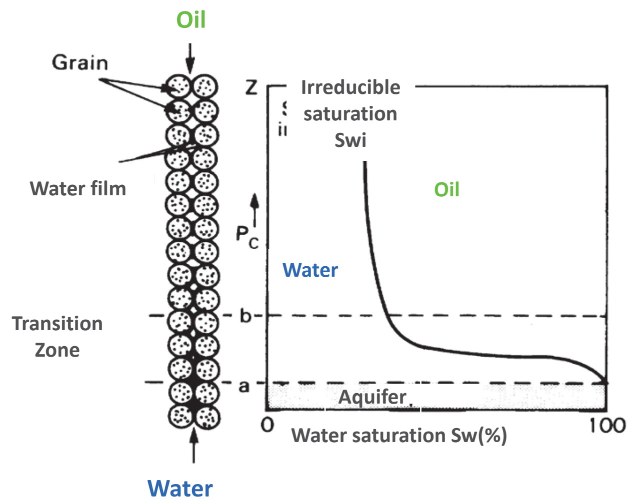
Capillarity and fluids distribution in the reservoir

Example of an oil reservoir



The transition zone is high when:

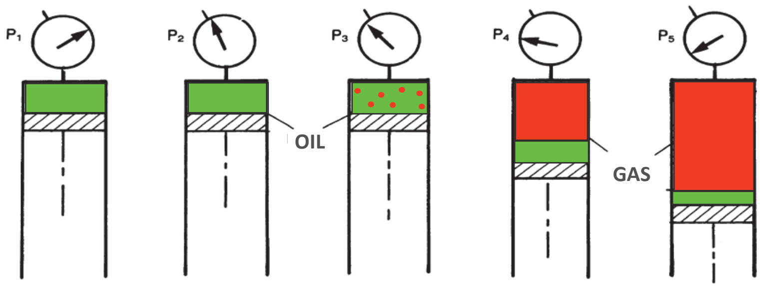
- The difference of density of the two fluids is low (so higher transition zone between water and oil than between water and gas)
- The pore diameters are smalls

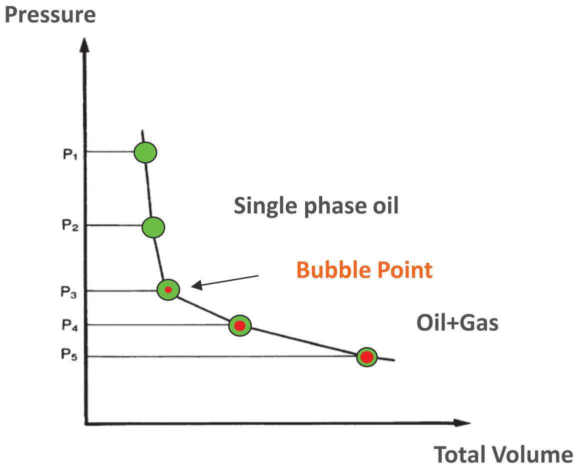


Effect of capillarity on S_w

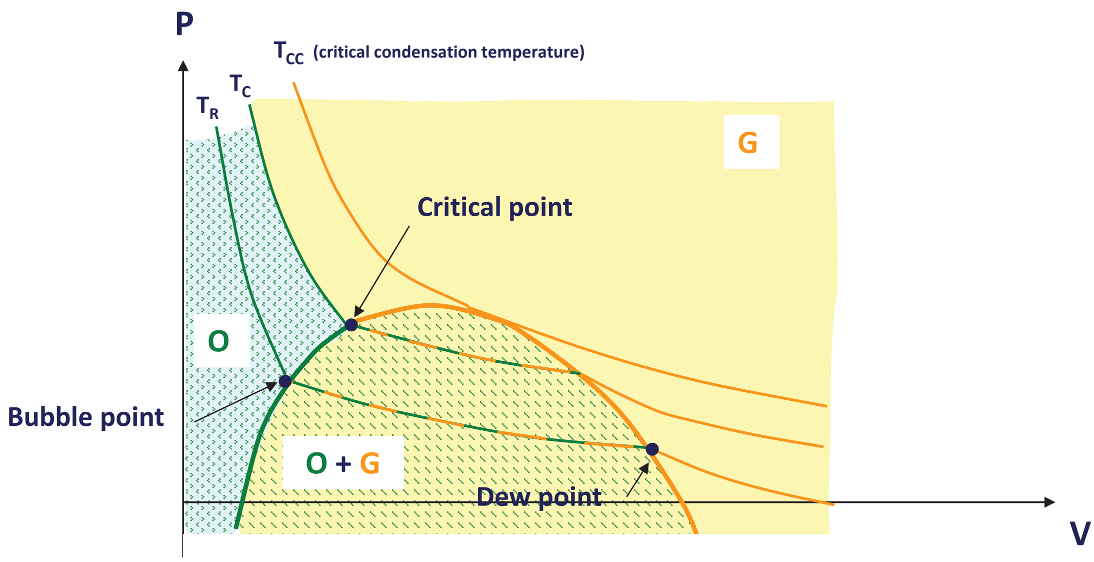
Fluid behaviour

Pressure - Volume diagram: decompressing an oil





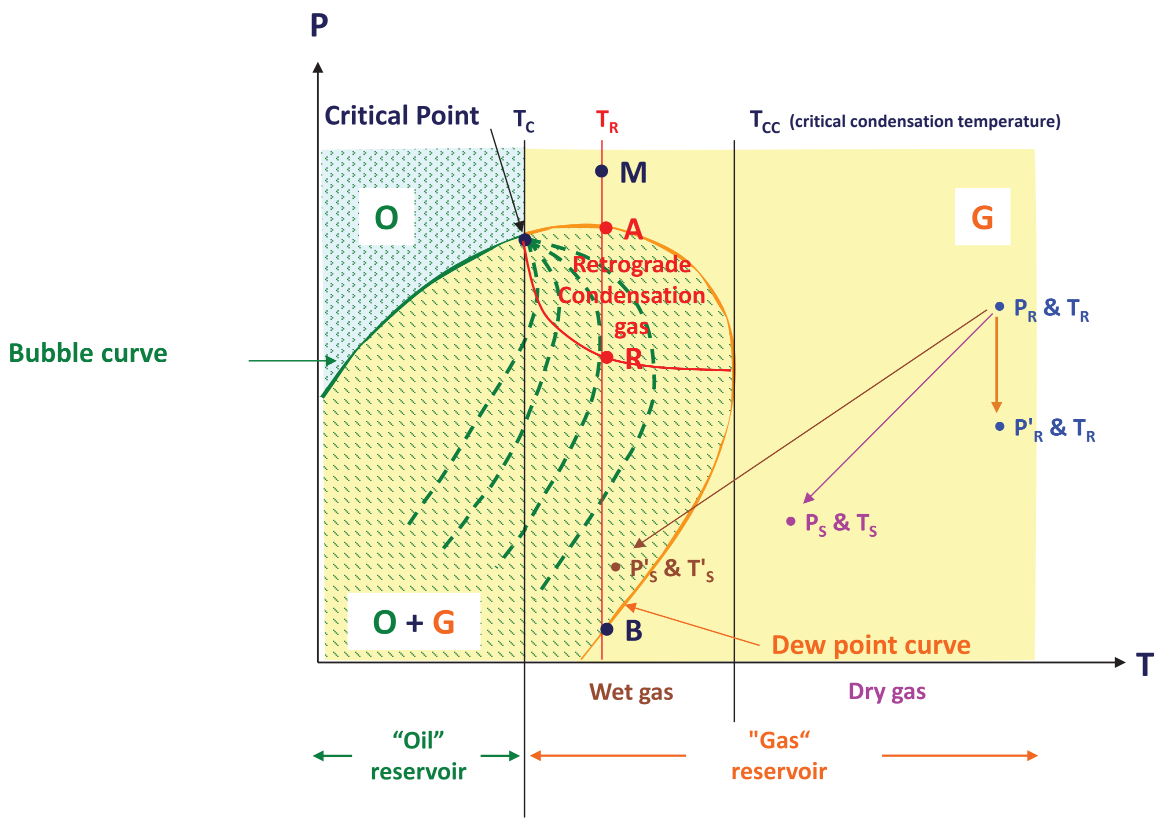
Pressure – Volume diagram



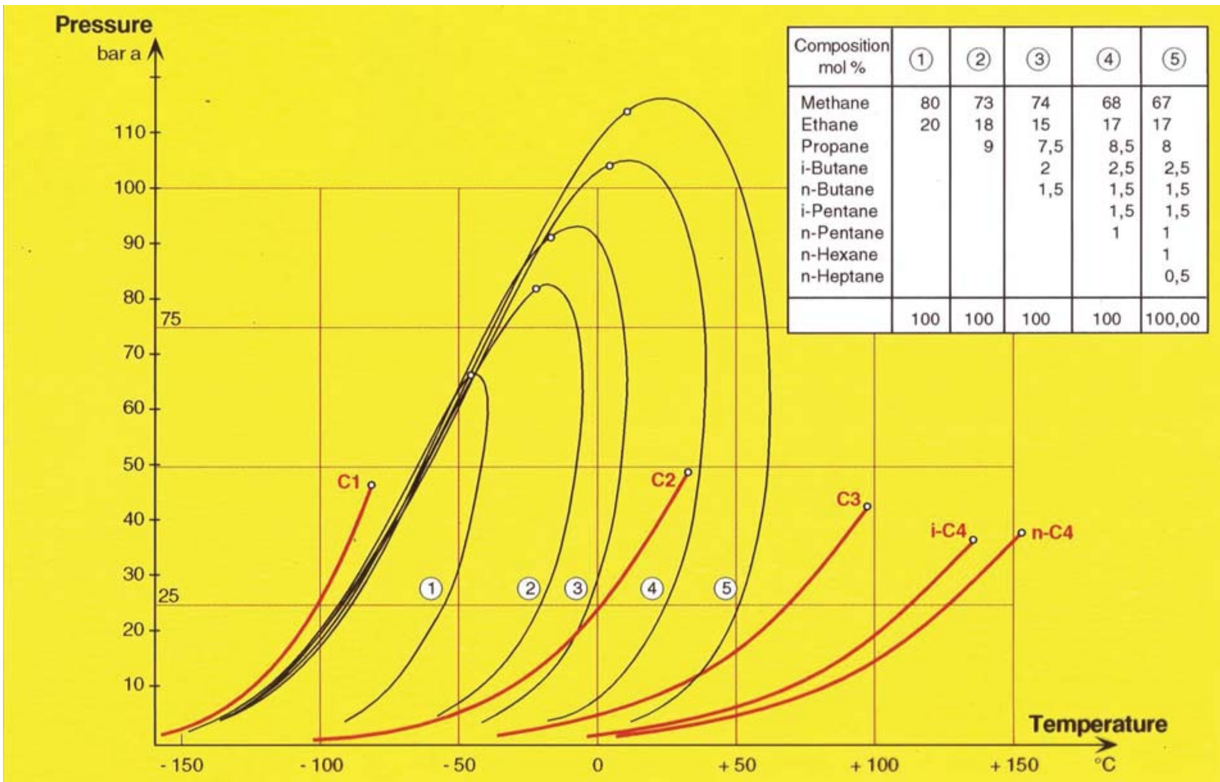
Bubble point pressure of an oil: pressure at which the first bubbles of gas evolves from the oil when the pressure decreases at a given temperature

Dew point pressure: pressure, at a given temperature, at which the first drops of condensate appear in a gas when the pressure varies

Pressure – Temperature diagram

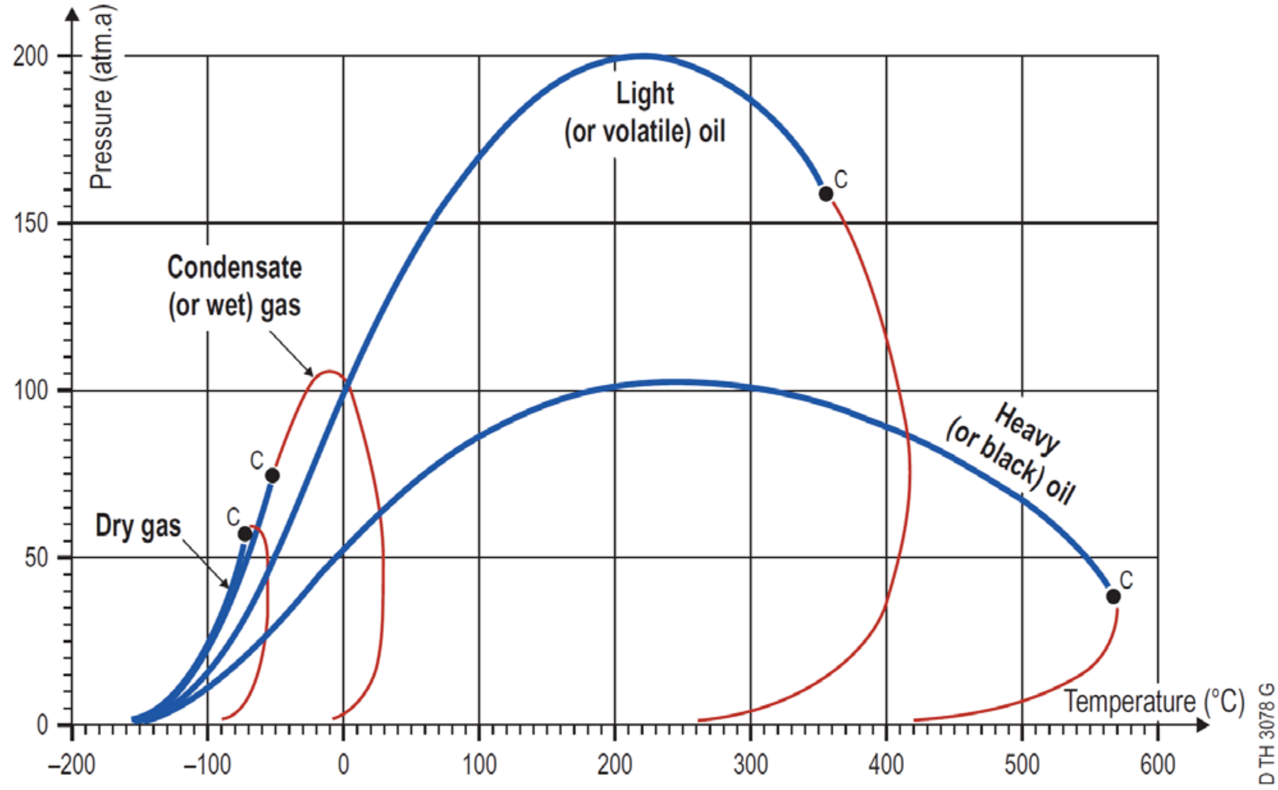


PT diagram in function of the gas composition

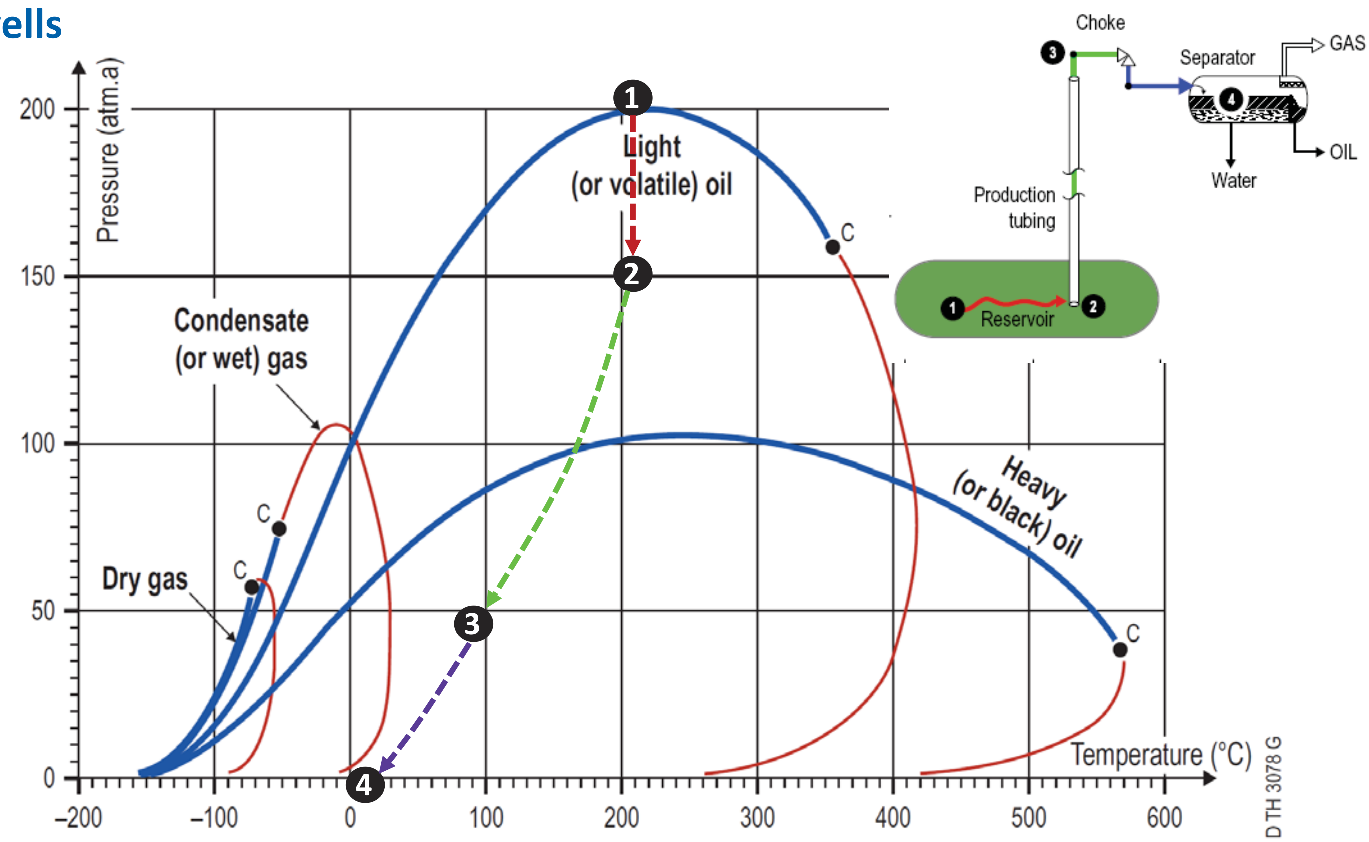


Composition mol %	1	2	3	4	5
Methane	80	73	74	68	67
Ethane	20	18	15	17	17
Propane		9	7,5	8,5	8
i-Butane			2	2,5	2,5
n-Butane			1,5	1,5	1,5
i-Pentane				1,5	1,5
n-Pentane				1	1
n-Hexane					1
n-Heptane					0,5
	100	100	100	100	100,00

Phase envelops of different effluents from oil or gas wells



Phase envelops of different effluents from oil or gas wells

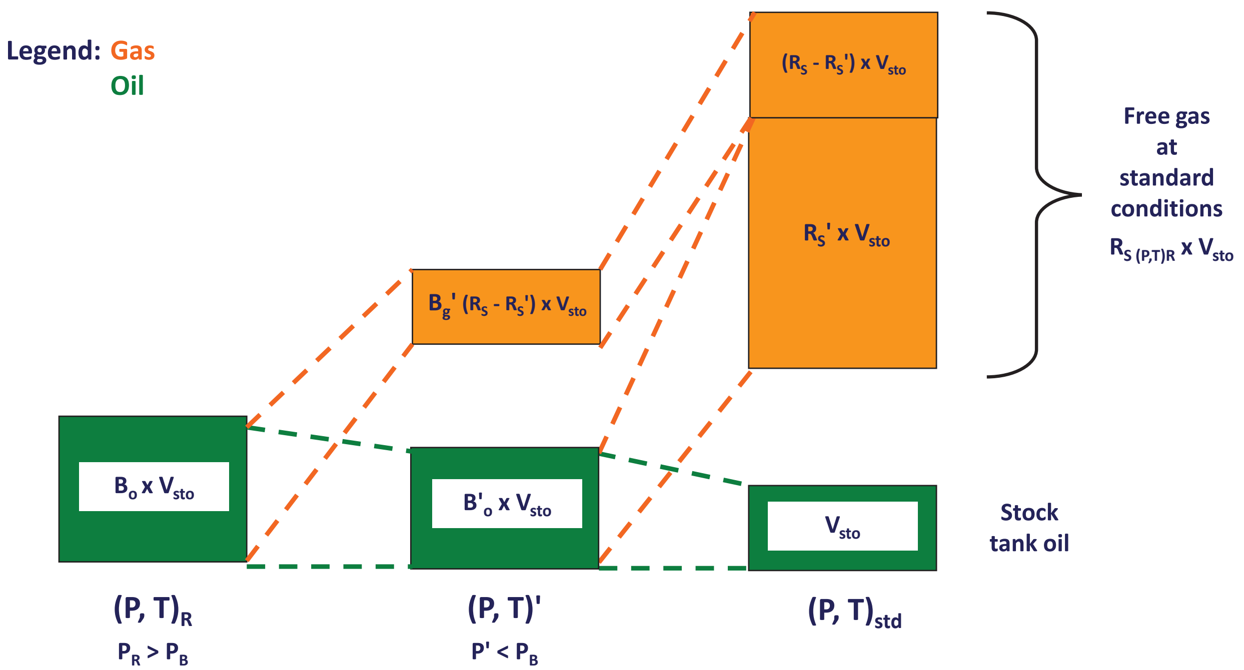


PVT terminology: glossary

- PVT study of a fluid
- Saturation curve of a fluid
- Bubble point curve
- Dew point curve
- Critical point
- Bubble point & bubble pressure at T_{given}: P_B
- Dew point & dew point pressure at T_{given}: P_{DP}
- Standard conditions (gas) :
  - Atmospheric pressure and 15 °C

    Or
  - Atmospheric pressure and 60 °F (careful: 60 °F = 15.6 °C ≠ 15 °C)
- Stock tank oil conditions (oil) → STO
- Solution GOR: $R_{s(P,T)}$*
- $B_{o(P,T)}$ & FVF, $B_{g(P,T)}$*

Illustration of the PVT terms R_s, B_o & B_g



$R_{s(P\&T)}$: **Solution gas/oil ratio** (see definition here after)
$B_{o(P\&T)}$: **Oil Formation Volume Factor (*Bulk oil*)** (see definition here after)
$B_{g(P\&T)}$: **Gas Formation Volume Factor (*Bulk gas*)** (see definition here after)

Definitions of the PVT terms R_s, B_o & B_g (1/2)

$R_{s(P\&T)}$: Solution gas/oil ratio at P&T

- Ratio between the "Volume of gas (expressed at standard conditions) in solution in the oil at P&T that evolves from it when pressure and temperature are reduced to standard conditions " and the "Corresponding dead oil volume (measured at standard conditions)"
- Expressed in Sm^3/m^3 ou scf/bbl; caution!: "dimensionless" but "with units" (the value of the ratio depends on the units: 1 $Sm^3/m^3 \approx 5.6$ scf/bbl)!
- Very variable from one oil to another (from 0 to more than 300 Sm^3/m^3 or 2000 scf/bbl)

$B_{o(P\&T)}$: Oil Formation Volume Factor (*Bulk oil*)

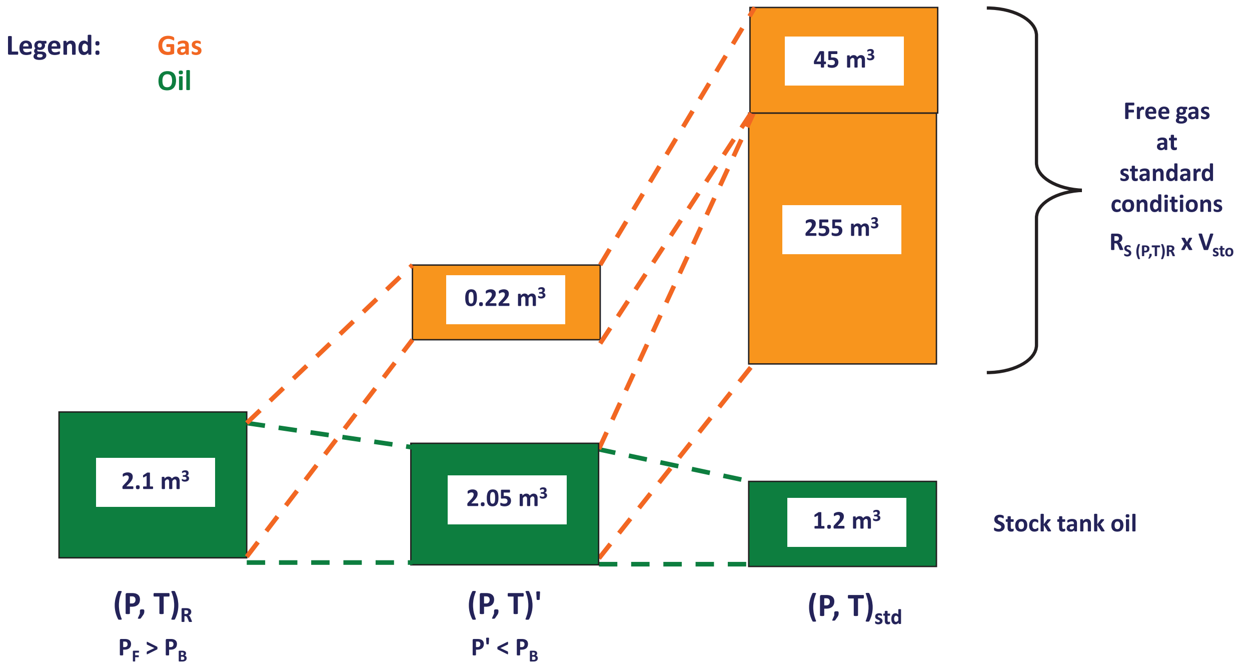
- Ratio between the "Volume of oil occupied at P&T conditions by the corresponding volumes of dead oil and it associated gas (free at standard conditions) which is in solution in the oil at P&T conditions" and the "Corresponding dead oil volume (measured at standard conditions)"
- Expressed in m^3/m^3 or bbl/bbl ; term "dimensionless" and "unit-less" (the value of the ratio does not depend on the units, although keep in mind it is a ratio between a "Reservoir volume" and a "Standard conditions volume")
- It is usually in the range of 1 to 2, depending mainly of R_s and T

Definitions of the PVT terms R_s, B_o & B_g (2/2)

$B_{g(P\&T)}$: Gas Formation Volume Factor (*Bulk gas*)

- Ration between the "Volume occupied by the free gas at P&T conditions" and the "Volume of this same mass of free gas at standard conditions"
- Express :
  - In the metric system: in m^3/Sm^3 (term "dimensionless" and "unit-less", although keep in mind it is a ratio between a "Reservoir volume" and a "Standard conditions volume")
  - In the US oil field system: in cft/Scft (term "dimensionless" and "unit-less", although keep in mind it is a ratio between a "Reservoir volume" and a "Standard conditions volume") or in bbl/scf or bbl/Mcf (caution!, in this case "dimensionless" but "with units"!)
- In m^3/Sm^3 or cft/Scft, it is usually in the range of $1/P_{bara}$ or $14.7/P_{psia}$ (with a correction factor usually between 0.7 and 1.2 depending on the non-perfect gas nature and the temperature)

Example of calculation of PVT terms B_o & R_s



Formation volume factor of the oil:

$B_{o(P\&T\ Reservoir)} =$

Solution gas/oil ratio:

$R_{s(P\&T\ Reservoir)} =$

Some "Production operations" terminology

- Production GOR: Gas produced / Oil produced: $GOR = \dfrac{G}{O}$
  - Beware of the units: Sm³/ m³ or scf/bbl (with 1 Sm³/m³ ≈ 5.6 scf/bbl)
  - Caution! Do not confuse the production GOR (GOR_{prod}) with the solution GOR (R_S) :
    - if $P_{BH} > P_B$, then $GOR_{prod} = R_S$

      but
    - If there is also free gas flowing from the reservoir, $GOR_{prod} > R_S$
- $$WOR = \frac{W}{O}$$
- $$\text{WLR or watercut} = \frac{W}{O+W} \qquad \text{with} \quad WLR = \frac{WOR}{1+WOR}$$
- $$GLR = \frac{G}{O+W} \qquad \text{with} \quad GLR = \frac{GOR}{1+WOR} = GOR\,(1-WLR)$$
- $$\text{BSW (Basic Sediment \& Water)} = \frac{S\,\&\,W}{O + S\,\&\,W}$$
- GPM : Caution — Gallons of condensate Per thousand scf of gas (note: thousand = M)

  or — Grams of condensate Per standard M³ of gas

Composition of hydrocarbons

OIL = ε (C_1 to C_4) + C_5^+

LIGHT oils	($d<=0.86$)	Gas + Oil	(surface conditions)
MEDIUM oils	($0,86<d<0,92$)	Gas/Oil <<	(surface conditions)
HEAVY oils	($d>0,92$)	ε Gas & Oil	(surface conditions)

GAS = C_1 + C_2 to C_4 + ε C_5^+

DRY gas	Gas	(surface conditions)
WET gas	Gas & ε Condensate	(surface conditions)
Gas CONDENSATE	Gas & Condensate	(surface conditions)

Hydrocarbon components

C_1 methane
C_2 ethane
C_3 propane
C_4 butane
C_5 pentane
C_6 hexane
C_7 heptane

Light and heavy oils

Type of Oil	Light	Medium	Heavy
Density (g/cm³)	0.80 to 0.82	0.83 to 0.90	0.91 to 1
° API	45	35	25 to 10
Volume Factor (volume reservoir/surface)	3 to 2	1.5	1.1 to 1
Gas/Oil Ratio (m³ gaz/m³ oil)	300 to 200	100	10 to 0
Viscosity (cP)	< 1 cP	several cP	up to 1 Po
Viscosity of water at 20°C and 1 atm. = 1cP Viscosity of gas 1/100 cP			

Overall approach of the well flow potential

Summary

- Base equations
- Productivity and flow efficiency
- Analysis of the different terms & Resulting conclusions
- Performance curves
- Extension of PI notion

Base equations

Base equations

- **Well flow potential:**

$$Q = f\left(P_R, P_{BH}, \frac{h\,k}{\mu}, S\right)$$

- **If steady-state (or pseudo steady-state) flow:**
  - Case of an oil flow: $Q = PI\,(P_R - P_{BH})$
  - Case of a gas flow (empirical law): $Q = C\,(P_R^2 - P_{BH}^2)^n$ with $0.5 < n < 1$

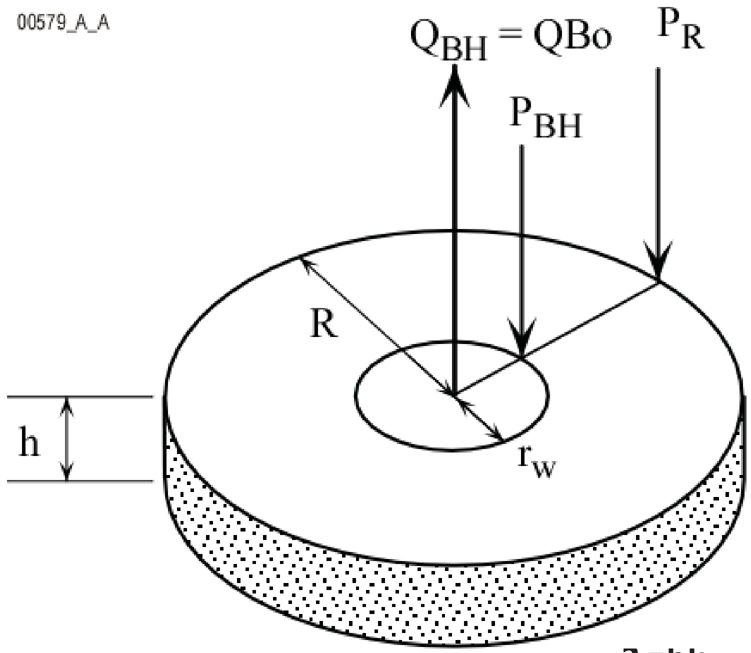
  with PI & C function of hk/μ and S

- **$P_{BH\ required}$ & $P_{BH\ available}$**
  - $P_{BH\ required} = P_{sep} + \Delta P_{fl} + P_{Hfl} + (\Delta P_{choke}) + \Delta P_{tbg} + P_{Htbg}$
  - $P_{BH\ available} = P_R - \Delta P_R$

    with $\Delta P_R = Q/PI$ if oil flowrate

Productivity index

(case of a liquid in steady-state and radial flow and for $P_{BH} > P_B$)



Bo : Oil bulk volume
h : Reservoir thickness
P_{BH} : Bottomhole pressure in well (when flowing)
P_R : Reservoir pressure
Q : Stock tank oil flowrate (Q_{sto})
Q_{BH} : Bottomhole flowrate
R : Well drainage radius
r_w : Wellbore radius

$$PI = \frac{2\pi hk}{B\mu \, Ln\frac{R}{r_w}}$$

Productivity Index & Flow efficiency

(case of a liquid in steady-state and radial flow)

- Actual PI (PI) for a steady-state and radial flow: $PI = \dfrac{2\pi hk}{B\mu\left(Ln\frac{R}{r_w} + S\right)}$

- Flow efficiency (Fe):

From a "Production" point of view:

$$Fe = \frac{PI}{PI_{th}} = \left[\frac{Q}{(P_R - P_{BH})}\right] \times \left[\frac{(P_R - P_{BH})_{th}}{Q_{th}}\right] = \left[\frac{(P_R - P_{BH})_{th}}{(P_R - P_{BH})}\right]_{Q=Cst} = \left[\frac{Q}{Q_{th}}\right]_{\Delta P=Cst}$$

From a "Reservoir engineering" point of view and for a steady-state and radial flow:

$$FE = \frac{PI}{PI_{th}} = \frac{\dfrac{2\pi hk}{B\mu\left(Ln\frac{R}{r_w} + S\right)}}{\dfrac{2\pi hk}{B\mu \, Ln\frac{R}{r_w}}} = \frac{Ln\frac{R}{r_w}}{Ln\frac{R}{r_w} + S}$$

Simplified form (for Ln R/r_w between 7 and 8): $FE = \dfrac{PI}{PI_{th}} \approx \dfrac{7}{7+S}$ to $\dfrac{8}{8+S}$

(usually it is considered that Ln $R/r_w \approx 7.6$)

Relationship between skin factor S and flow efficiency Fe

(case of a liquid in steady-state and radial flow & for Ln R/rw = 7.6)

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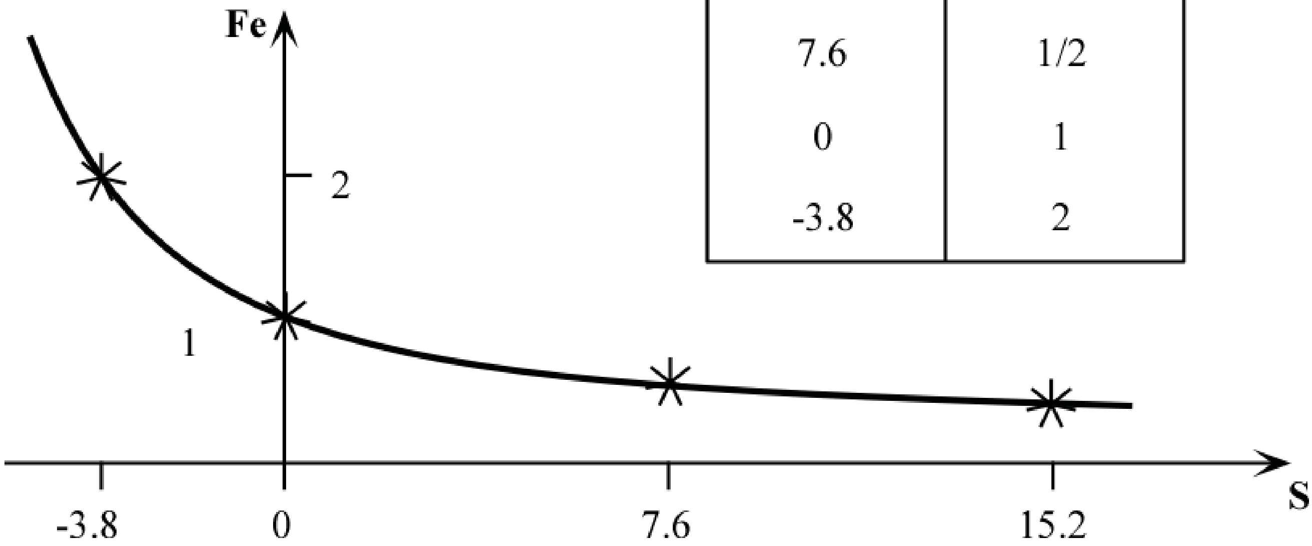
S	Fe
15.2	1/3
7.6	1/2
0	1
-3.8	2



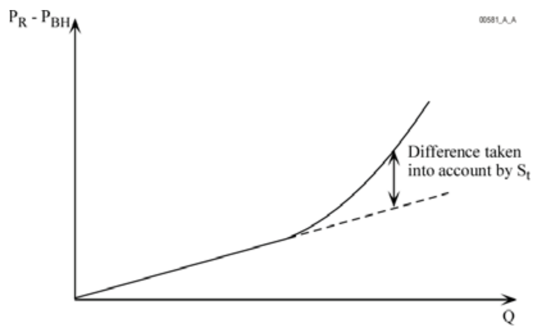
Parameter included in the global skin S

(steady-state and radial flow)

- S = 0 :
  - No damage
  - Well fully open (open hole) on all the height of the pay zone
  - Well drilled perpendicular to the pay zone ("vertical")
  - No turbulence (laminar flow)
- S_d (damage):
  - $0 < S_d < +\infty$
  - $S_d = f(k_d/k_o, r_d)$
  - After treatment: $S_{d\ after\ treatment}$: + ∞ to ~~0 ⇒ - 1~~ + ∞ to 0 & perhaps - 2 (or even - 4)
- S_p (perforation):
  - $-1 < S_p < 0$ (or + 1)
  - $S_p = f$(penetration, phasing, SPF, k_v/k_h)
- S_{pp} (partial penetration):
  - $0 < S_{pp} < +7$ (or more)
  - $S_{pp} = f(h_p/h_u$, pattern, $k_v/k_h)$
- S_θ (deviation or inclination of a slanted well):
  - (- 3 to) $-1.5 < S_\theta < 0$
  - $S_\theta = f(\theta, k_v/k_h)$
- S_t* (turbulence)
- ...
- $S_{global\ (from\ well\ test)} = f(S_d, S_p, S_{pp}, S_\theta, ...)$

⇒ don't confuse S_{global} and S_d

$S_{global} > 0$ don't automatically imply $S_d > 0$



Turbulence effect

Practical formulas for PI & Fe (for Ln R/rw =7.6*)

(case of a liquid in steady-state and radial flow)

- $$PI_{(m^3/d/bar)} = \frac{h_{(m)} \times k_{(mD)}}{18.7 \times B_o \times \mu_{(cP)} \times (7.6+S)}$$ with: 18.7 x 7.6 = 142

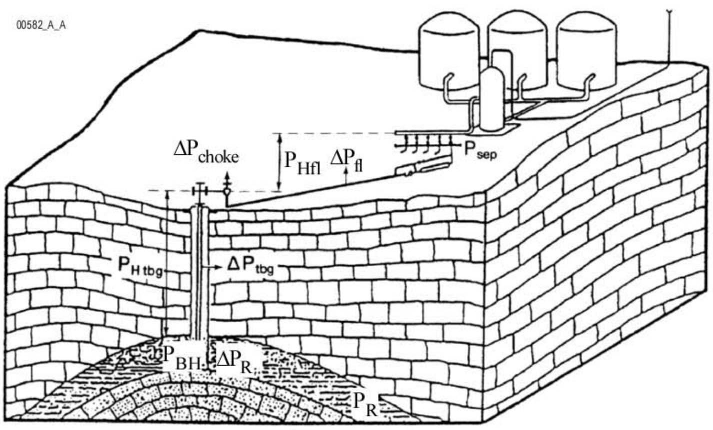
- $$PI_{(bbl/d/psi)} = \frac{h_{(ft)} \times k_{(mD)}}{141 \times B_o \times \mu_{(cP)} \times (7.6+S)}$$ with: 141 x 7.6 = 1 072

- $$FE \approx \frac{7.6}{7.6+S}$$

Note: 1 m^3/d/bar ≈ 0.43 bbl/d/psi & 1 bbl/d/psi ≈ 2.3 m^3/d/bar

*: Ln R/rw = 7.6 correspond to a drainage radius of 200 m (656 ft) for 8" 1/2 drilling diameter

Fluid path from the reservoir to the process facilities



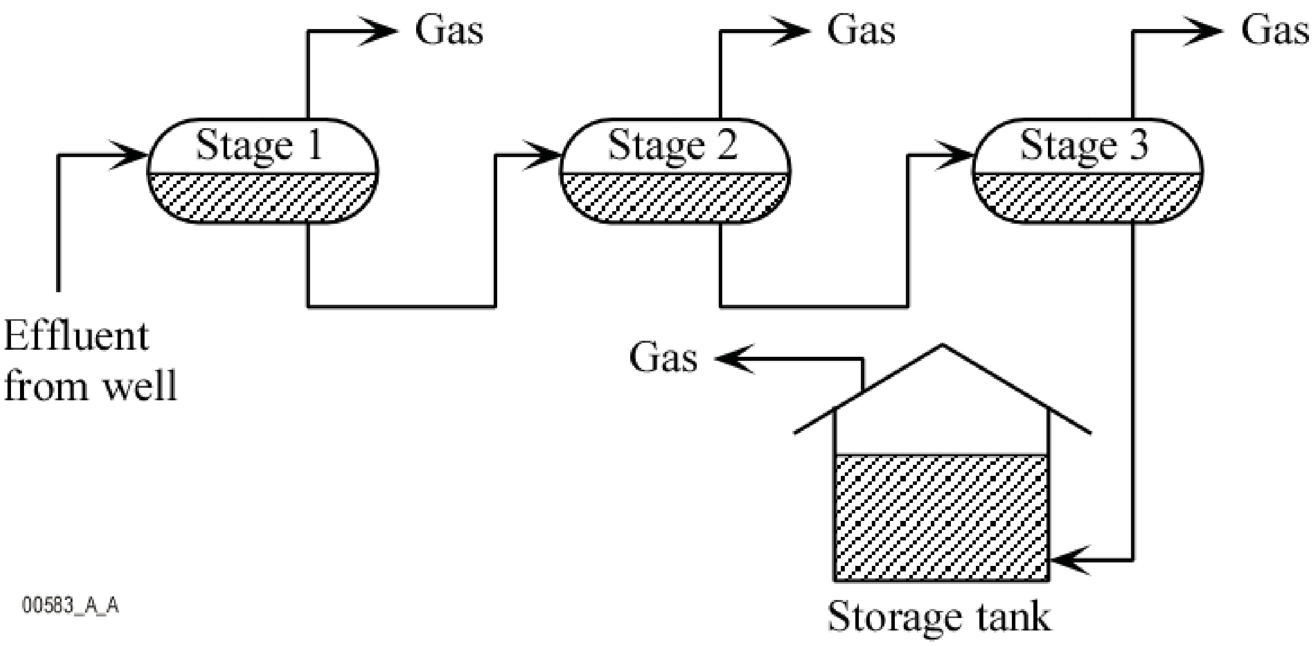
P_R	=	Reservoir pressure
ΔP_R	=	Pressure losses in the reservoir
P_{BH}	=	Bottomhole pressure
P_{Htbg}	=	Hydrostatic pressure in the tubing
ΔP_{tbg}	=	Pressure losses in the tubing
ΔP_{choke}	=	Pressure losses in the choke
P_{Hfl}	=	Hydrostatic pressure in the flowlines
ΔP_{fl}	=	Pressure losses in the flowlines
P_{sep}	=	Pressure at the surface treatment facility inlet

$P_{BH\ required} = P_{sep}^{*} + \Delta P_{fl} + P_{Hfl} + (\Delta P_{choke}) + \Delta P_{tbg} + P_{Htbg}^{*}$ [outflow]

$P_{BH\ available} = P_R - \Delta P_R$ [inflow]

with $\Delta P_R = Q/PI$ if oil flowrate

Multistage separation



Hydrostatic pressure

- **Hydrostatic pressure:**
  - $$P_{h(MPa)} = \frac{9.81 \times Z_{(m)} \times d_{(kg/l)}}{1\,000}$$ Note: 1 MPa = 10 bar

    or
  - $$P_{h(bar)} = \frac{9.81 \times Z_{(m)} \times d_{(kg/l)}}{100} \text{ ou } \frac{Z_{(m)} \times d_{(kg/l)}}{10.2}$$ Note: 1 bar = 0.1 MPa

    or
  - $P_{h(psi)} = 0.052 \times MW_{(ppg)} \times Z_{(ft)}$

    or

    $= 0.433 \times SG \times Z_{(ft)}$

Conversion factors:

- 1 MPa = 145 psi — 1 psi = $6.895\ 10^{-3}$ MPa
- 1 m = 3.281 ft — 1 ft = 0.3048 m
- 1 kg/l = 8.345 ppg — 1 ppg = 0.1198 kg/l
- 1 kg/l = 62.43 lb/ft³ — 1 lb/ft³ = 0.01602 kg/l

Study of $BHP_{required}$ (1/4)

- **Oil well (3000 m – 10,000 ft)**

	bar	psi
• P_{sep}		
• ΔP_{fl}		
• $P_{H\ fl}$		
• ΔP_{tbg}		
• $P_{H\ tbg}$		

Note:

- 560 scuft = 100 bbl 1 atm = 14.7 psia
- P_H(psi) = 0.433 x SG x Z(ft) = 0.052 d(ppg) x Z(ft)
- Water density at 20°C or 68°F: 1 kg/l = 8.33 ppg = 62.3 lbs/ft^3
- Air density at 60°F & 14.7 psia: 0.0764 lbs/ft^3 = 1.23 g/l

Study of $BHP_{required}$ (2/4)

- **Gas well (3000 m – 10,000 ft)**

	bar	psi
• P_{sep}		
• ΔP_{fl}		
• $P_{H\ fl}$		
• ΔP_{tbg}		
• $P_{H\ tbg}$		

Study of $BHP_{required}$ (3/4)

- Gas well (3000 m – 10 000 ft): Determination of WHP (in bar)

Study of $BHP_{required}$ (4/4)

- Gas well (3000 m – 10 000 ft): Determination of WHP (in psi)

Effect of a damage around the wellbore: example

(case of a liquid in steady-state and radial flow)

Exercise N° 1

Data: P_R = 360 bar, k_O = 90 mD & ΔP_{th} = 20 bar for Q = 300 m³/d

	For Q = 300 m³/d & $k_{(1-0.1\ m)}$ = 90 mD	$k_{(1-0.1\ m)}$ = 9 mD	$k_{(1-0.1\ m)}$ = 900 mD	For ΔP_R = 20 bar & $k_{(1-0.1\ m)}$ = 9 mD
Flow rate	Q = 300 m³/d	Q = 300 m³/d	Q = 300 m³/d	Q' = Q x ………………… = …………………………….
$\Delta P_{(1000-100\ m)}$				
$\Delta P_{(100-10\ m)}$				
$\Delta P_{(10-1\ m)}$				
$\Delta P_{(1-0.1\ m)}$				
$\Delta P_R = \Delta P_{(1000-0.1\ m)}$	20			20
$\Delta P_{(1-0.1\ m)}/\Delta P_R$				
P_{BH} = ………………………				
FE [flow efficency]				

Effect of a damage around the wellbore: example

(case of a liquid in steady-state and radial flow)

Exercise N° 1 US field Unit

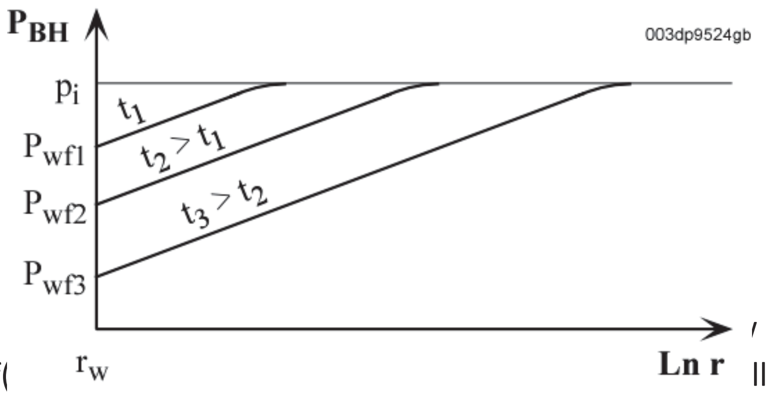
Data: P_R = 3600 psi, k_O = 90 mD & ΔP_{th} = 200 psi for Q = 2000 bpd

	For Q = 2000 bpd & $k_{(3-0.3\ ft)}$ = 90 mD	$k_{(3-0.3\ ft)}$ = 9 mD	$k_{(3-0.3\ ft)}$ = 900 mD	For ΔP_R = 200 psi & $k_{(3-0.3\ ft)}$ = 9 mD
Flow rate	Q = 2000 bpd	Q = 2000 bpd	Q = 2000 bpd	Q' = Q x ………………… = …………………………….
$\Delta P_{(3000-300\ ft)}$				
$\Delta P_{(300-30\ ft)}$				
$\Delta P_{(30-3\ ft)}$				
$\Delta P_{(3-0.3\ ft)}$				
$\Delta P_R = \Delta P_{(3000-0.3\ ft)}$	200			200
$\Delta P_{(3-0.3\ ft)}/\Delta P_R$				
P_{BH} = ………………………				
FE [flow efficency]				

Productivity index & flow efficiency

Infinite extent reservoir (or boundaries not yet reached)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**



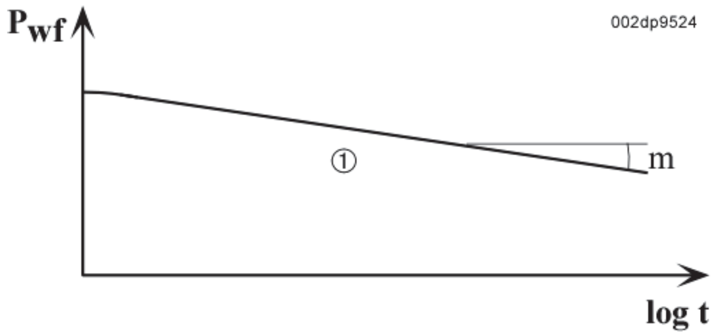
- $P_i = P_r$
- $P_{wf} = f($

P_{wf} decreasing when t increasing

- $P_i - P_{wf} = f(t)$ ⇒ transient flow

Infinite extent reservoir (or boundaries not yet reached) (cont)

- **"P_{wf} versus log t" diagram (excluding capacity and skin effects):**

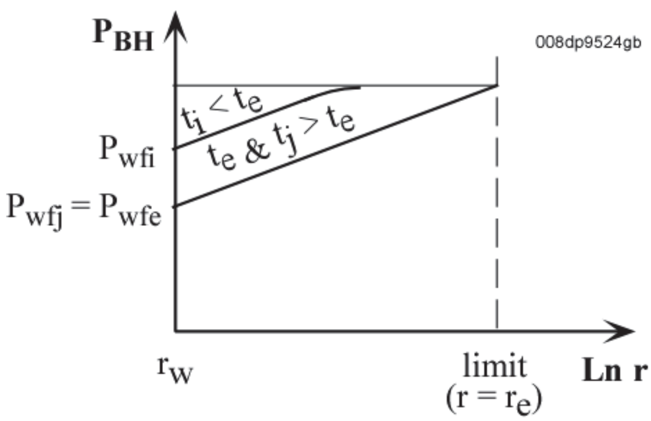


- For "t great enough": $P_{wf} = P_i - m \log t$ $\Rightarrow$ transient flow

Case of a limited reservoir with constant pressure at the boundaries

In this case, it is considered that the pressure at the limit of the reservoir is maintained constant (perfect water drive or water flooding with perfect pressure maintenance for example)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**

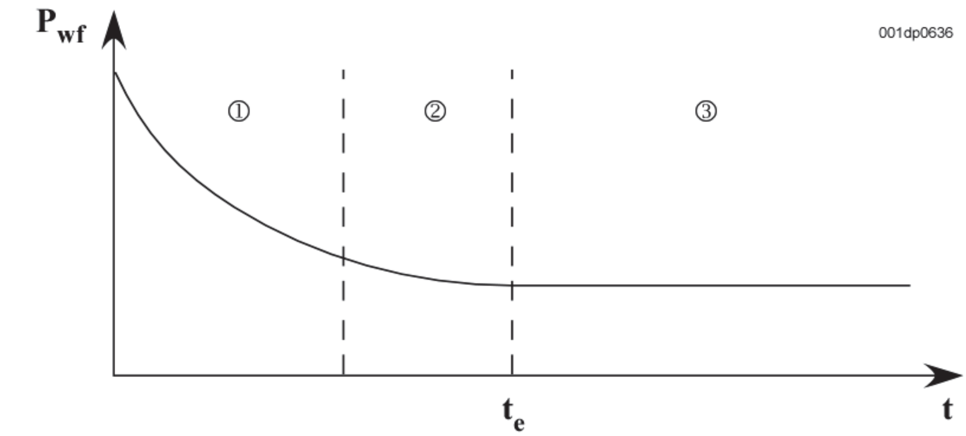


- For "t > t_e": P_{wf} = cst & $P_i - P_{wf}$ = cst $\Rightarrow$ steady state flow

  (this type of flow is usually not reached during a well test when drilling, the well test duration being too short)

Case of a limited reservoir with constant pressure at the boundaries (cont.)

- **"P_{wf} versus t" diagram (excluding capacity and skin effects):**



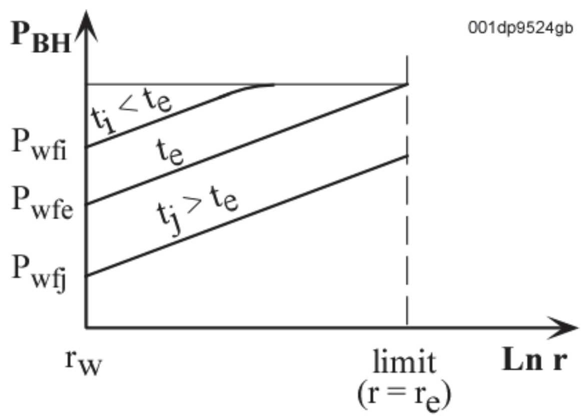
① Transient flow (reservoir acting as infinite): $P_{wf} = P_{1h} - m \log t$
②Transition zone
③ Steady state flow: $P_{wf} = cst$

- For "$t > t_e$": $P_{wf} = cst$ & $P_i - P_{wf} = cst$ ⇒ steady state flow

Case of a limited reservoir with no flow at the boundaries

In this case, the reservoir is considered fully isolated from the outside by barriers allowing no communication (perfectly sealed reservoir)

- **"P_{BH} versus Ln r" diagram (excluding capacity and skin effects):**



For $t > t_e$, production is obtain only by decompression

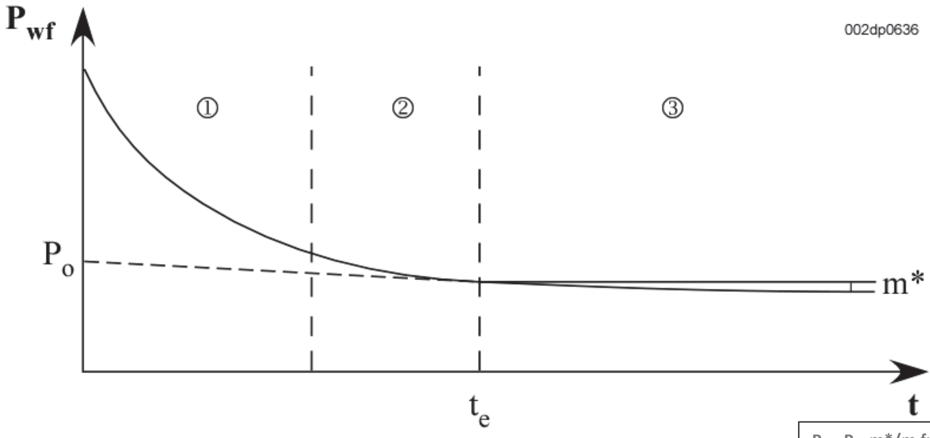
$\bar{P}$ = average pressure in the reservoir (once the well is shut back)

- For "$t > t_e$": $P_{wf} = f(t)$ but $\bar{P} - P_{wf} = cst$ ⇒ pseudo steady state flow

(this type of flow is usually not fully reached during a well test when drilling, the well test duration being too short)

Case of a limited reservoir with no flow at the boundaries (cont.)

- **"P_{wf} versus t" diagram (excluding capacity and skin effects):**



① Transient flow (reservoir acting as infinite): $P_{wf} = P_{1h} - m \log t$
②Transition zone
③ Pseudo steady state flow: $P_{wf} = P_o - m^* t$

P_{1h}, P_o, m*/m function of:
- the shape of the limits
- the relative position of the well compared to the limits

- For "$t > t_e$": $P_{wf} = f(t)$ but $\overline{P} - P_{wf} = cst \Rightarrow$ pseudo steady state flow

Theoretical formulas

	Transient flow	Pseudo steady state flow	Steady state flow
	Infinite reservoir (or boundaries not yet reached)	*No flow boundaries*	*Constant pressure boundaries*
"P_r"	$P_r = P_i = P^* = cst$	$"P_r" = \overline{P} = f(t)$	$P_r = P_i = cst$
P_{wf}	$P_{wf} = P_{1h} - m \log t$	$P_{wf} = P_0 - m * t$	$P_{wf} = P_0 = cst$
"P_r" - P_{wf}	$P_i - P_{wf} = f(t) = \alpha \log t + \beta$	$\overline{P} - P_{wf} = cst$	$P_i - P_{wf} = cst$
"PI"	$\cancel{\frac{q}{P_i - P_{wf}} = f(t) = \frac{4\pi k h}{B\mu\left(\ln\frac{Kt}{r_w^2} + 0.81 + 2S\right)}}$ $\Rightarrow$ the flowrate can't be characterised by a PI	$PI = \frac{q}{P - P_{wf}} = cst = \frac{2\pi k h}{B\mu\left(\ln\frac{r_e}{r_w} + S - 0.75\right)}$	$PI = \frac{q}{P_i - P_{wf}} = cst = \frac{2\pi k h}{B\mu\left(\ln\frac{r_e}{r_w} + S\right)}$
"J"	$\cancel{\frac{\ln\frac{Kt}{r_w^2} + 0.81}{\ln\frac{Kt}{r_w^2} + 0.81 + 2S} \text{ with } K = \frac{k}{\Phi\mu c_t}}$	$J = \frac{\ln\frac{r_e}{r_w} - 0.75}{\ln\frac{r_e}{r_w} + S - 0.75}$	$J = \frac{\ln\frac{r_e}{r_w}}{\ln\frac{r_e}{r_w} + S}$
S		$S = \left(\frac{1-J}{J}\right)\left(\ln\frac{r_e}{r_w} - 0.75\right)$	$S = \left(\frac{1-J}{J}\right)\ln\frac{r_e}{r_w}$

- With **P*** extrapolate on the Horner plot for $(t_p + \Delta t)/\Delta t = 1$
- With $\overline{P}$ worked out from **P*** with an suitable method, for example M.B.H. method (Mathew – Brons – Hazebrock)
- Furthermore: $\Delta P_{skin} = \frac{q B \mu}{2\pi k h} S$

Practical formulas for:

- Practical units defined in the table next page
- $\ln(R/r_w) = 7.6$ i.e. $\log(R/r_w) = 3.3$ or $R = 200$ m if $r_w = 0.1$ m

	Transient flow	Pseudo steady state flow	Steady state flow
	Infinite reservoir *(or boundaries not yet reached)*	*No flow boundaries*	*Constant pressure boundaries*
PI practical	$\cancel{\text{"PI"} = \dfrac{k\,h}{21.5\,B\,\mu\left(\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]+0.87\,S\right)}}$ $\Rightarrow$ the flowrate can't be characterised by a PI	$PI = \dfrac{k\,h}{B\,\mu\,(128 + 18.7\,S)}$	$PI = \dfrac{k\,h}{B\,\mu\,(142 + 18.7\,S)}$
J practical	$\cancel{J = \dfrac{\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]}{\log\left[\dfrac{8\times10^{-4}\,k\,t}{\Phi\,\mu\,c_t\,r_w^2}\right]+0.87\,S}}$	$J = \dfrac{6.85}{6.85 + S}$	$J = \dfrac{7.6}{7.6 + S}$
S practical		$S = 6.85\left(\dfrac{1-J}{J}\right)$	$S = 7.6\left(\dfrac{1-J}{J}\right)$

Furthermore: $\Delta P_{skin\ \ practical} = 18.7\,\dfrac{q\,B\,\mu}{k\,h}\,S$

Practical units

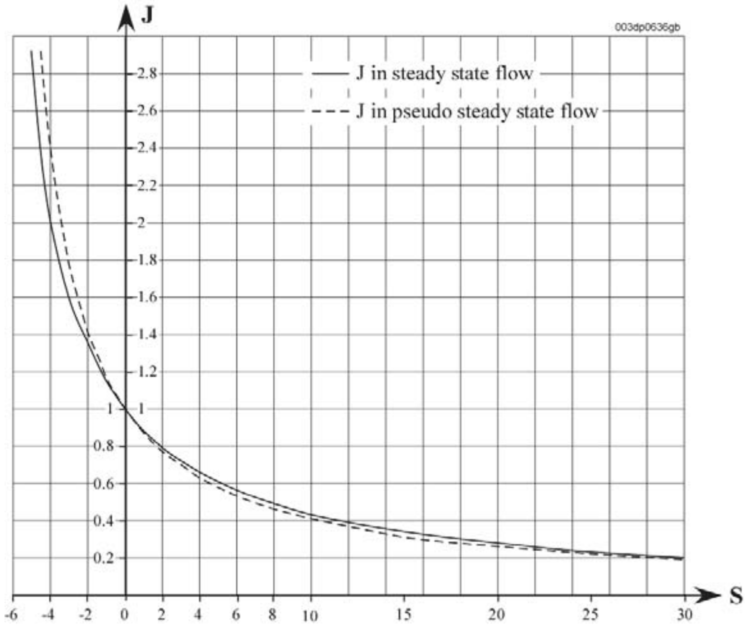
Parameters	Practical French units	Value in SI units
A (area)	m^2	1 m^2
c (compressibility)	bar^{-1}	10^{-5} Pa^{-1}
C (capacity)	m^3/bar	10^{-5} $m^3 \cdot Pa^{-1}$
h, r, l (height, radius, length)	m	1 m
k (permeability)	mD	0.987 x 10^{-15} m^2
K (diffusivity)	mD.bar/cP	0.987 x 10^{-7} x $m^2.s^{-1}$
m (slope of a straight line)	bar/cycle $\log_{10}$	10^5 Pa/cycle $\log_{10}$ (or 2.3 x 10^5 Pa/cycle ln)
P (pressure)	bar	10^5 Pa
q (flowrate)	m^3/j	(1 / 86,400) $m^3.s^{-1}$
t (time)	h	3600 s
T (temperature)	°K	1°K
μ (viscosity)	cP	10^{-3} Pa.s (*)
Ø (porosity)	fraction	fraction

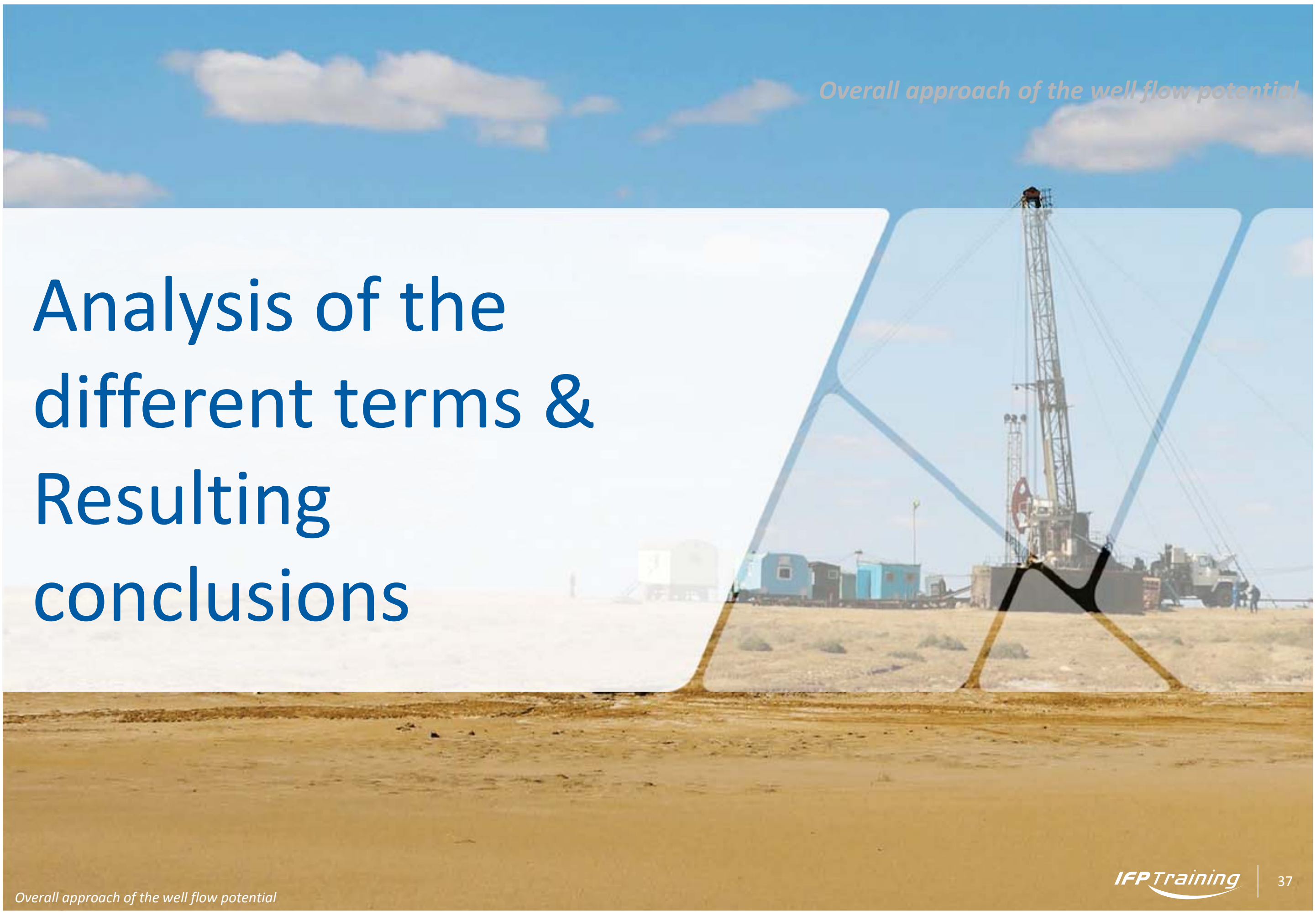
(*) 1 Pa.s = 1 Pl (Poiseuille)

Curves "Flow efficiency versus skin" (for Ln R/r_w = 7.6)

S	- 5	- 4	- 3	- 2	- 1	0	1	2	3	4	6	8	10	15	20	25	30
J_{st}	2.92	2.11	1.65	1.36	1.15	1	0.88	0.79	0.72	0.66	0.56	0.49	0.43	0.34	0.28	0.23	0.20
J_{pst}	3.7	2.4	1.78	1.41	1.17	1	0.87	0.77	0.70	0.63	0.53	0.46	0.41	0.31	0.26	0.22	0.19

with J_{st} = Flow efficiency in steady state flow
J_{pst} = Flow efficiency in pseudo steady state flow





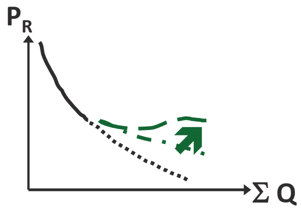
Analysis of the different terms & Resulting conclusions

Analysis of the different terms & Resulting conclusion

SECONDARY RECOVERY:

– *PRESSURE MAINTENANCE:*
  - To (avoid or) limit problems
  (- Help for flowing)

– *SWEEPING EFFECT*



$$Q = f\left(P_R, P_{BH}, \frac{hk}{\mu}, S\right)$$

- ΔP_{FL}, ΔP_{tbg} optimisation
- P_{sep} optimisation
- If oil well, ↘ P_{Htbg}: ARTIFICIAL LIFT
  - – ↘ "Z": *PUMPING*
  - – ↘ "ρ": *GAS LIFT*
- If gas well, compressor at the surface (if necessary)

PI, C ↗: STIMULATION

- $S_d > 0$: matrix treatment
  - – *ACIDIZING*
  - – *Solvents*
- $k_{natural}$ small or very small:
  - – *HYDRAULIC FRAC*
  - – *(Horizontal drain)*

- μ high or very high:
  - – *THERMAL METHODS*
  (classified as "SECONDARY or even TERTIARY RECOVERY)

Note:

For an oil well (with $P_{BH} > P_B$):
$Q = PI\,(P_R - P_{BH})$

For a gas well (empirical law):
$Q = C\left(P_R^2 - P_{BH}^2\right)^n$ with $0.5 < n < 1$

with PI & C function of hk/μ & S

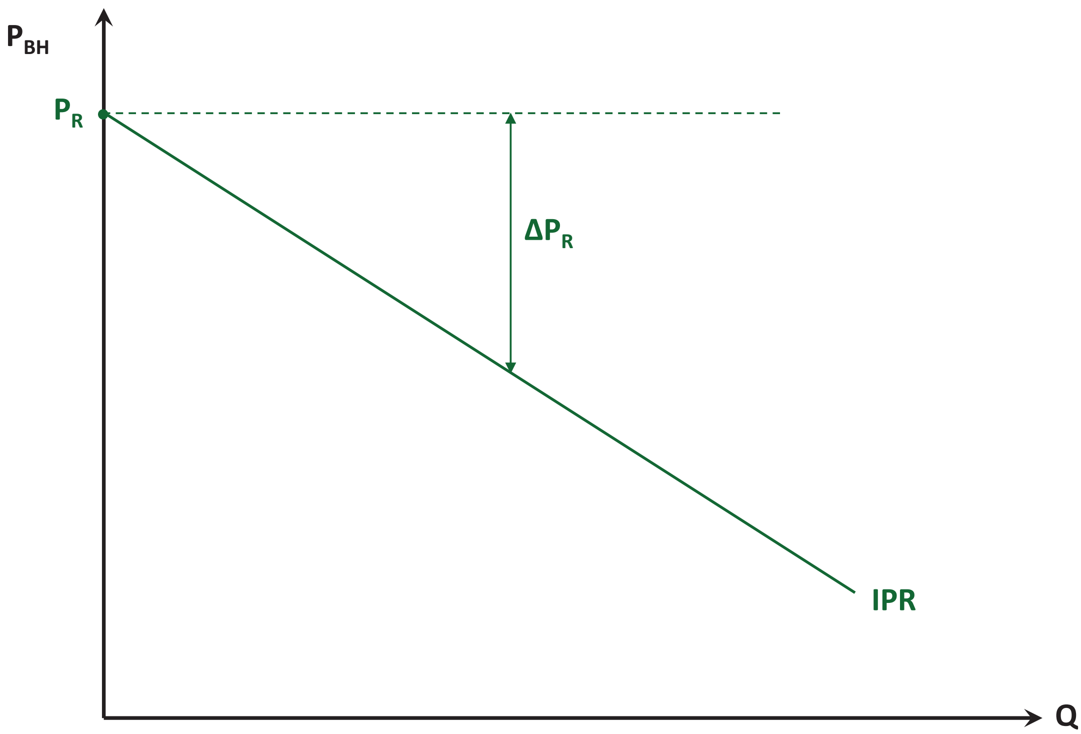
Analysis of the different terms & Resulting conclusion (cont.)

- **Decreasing P_{BH}:**
  - Case of an oil well:
    - Moderate P_{sep}
    - Small ΔP_{tbg}
    - Decreasing P_H: pumping, gas-lift ⇒ Artificial lift
  - Case of a gas well:
    - Small ΔP_{tbg}
    - Recompression on surface
- **Increasing productivity:**
    - Acidizing, fracturing… ⇒ Stimulation
- **Slowing down the decline of P_R:**
    - Water (or gas) injection ⇒ Secondary recovery

Performance curves

IPR curve in monophasic flow

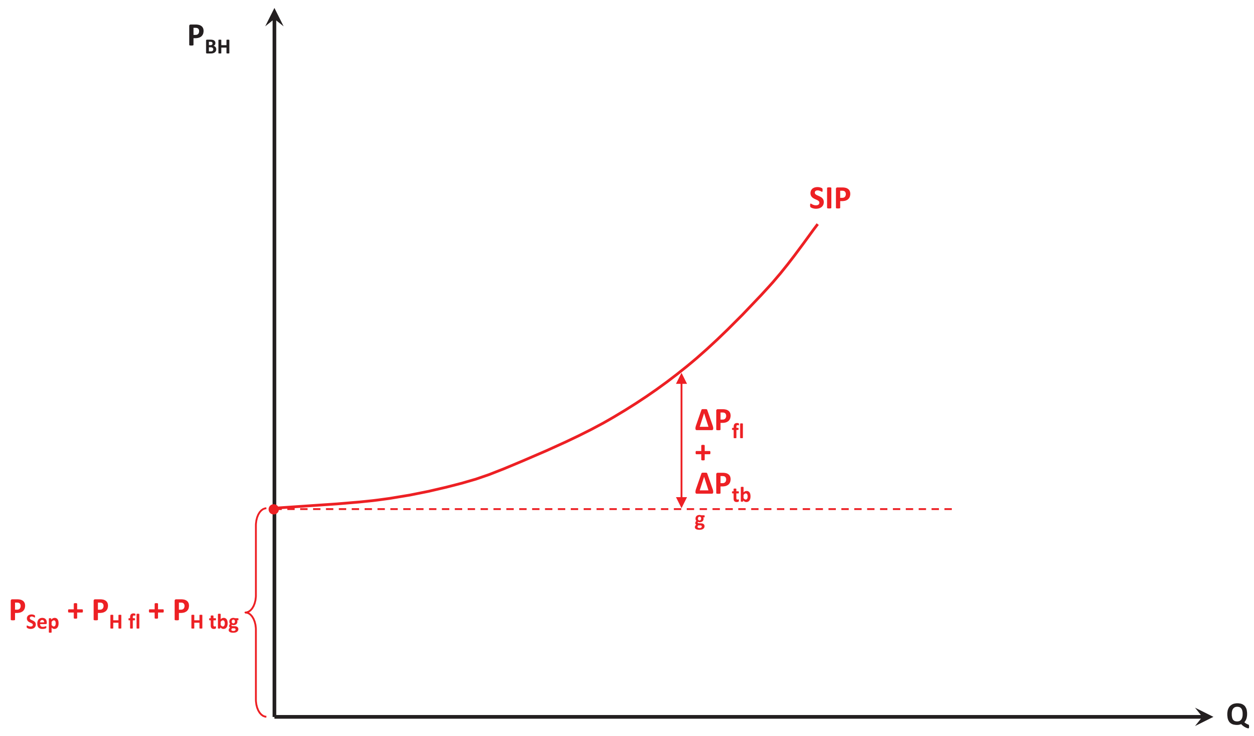
(Inflow Performance Response curve)



IPR: Inflow performance response curve

SIP curve in monophasic flow

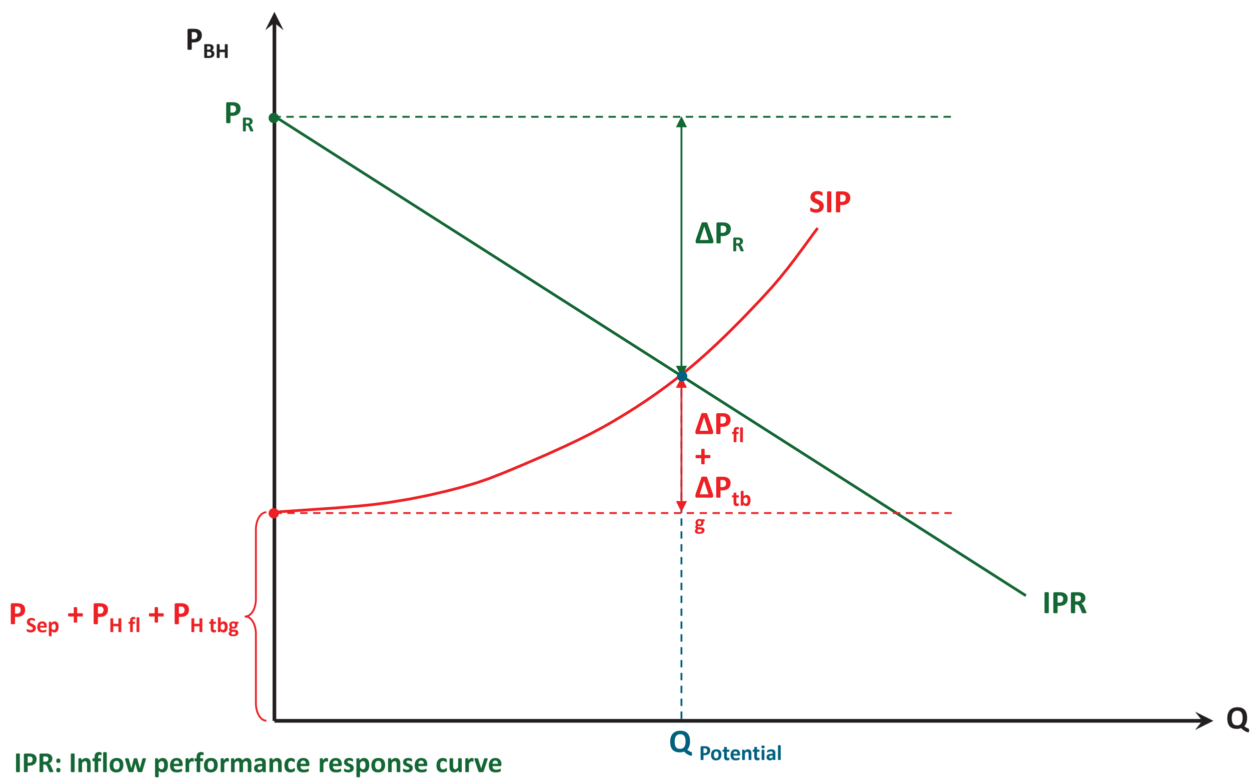
(System Intake Performance curve: outflow)



SIP: System intake performance curve (also called "VLP": Vertical lift performance)

IPR & SIP curves in monophasic flow

(Inflow & outflow)

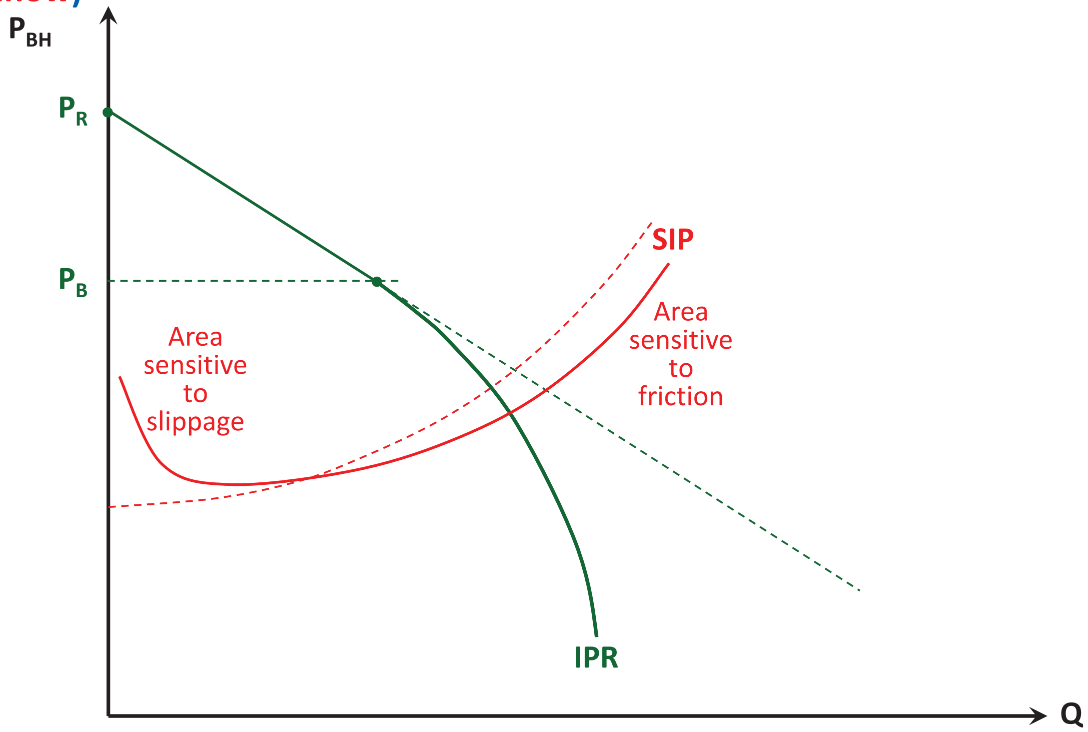


IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

IPR & SIP curves in polyphasic flow

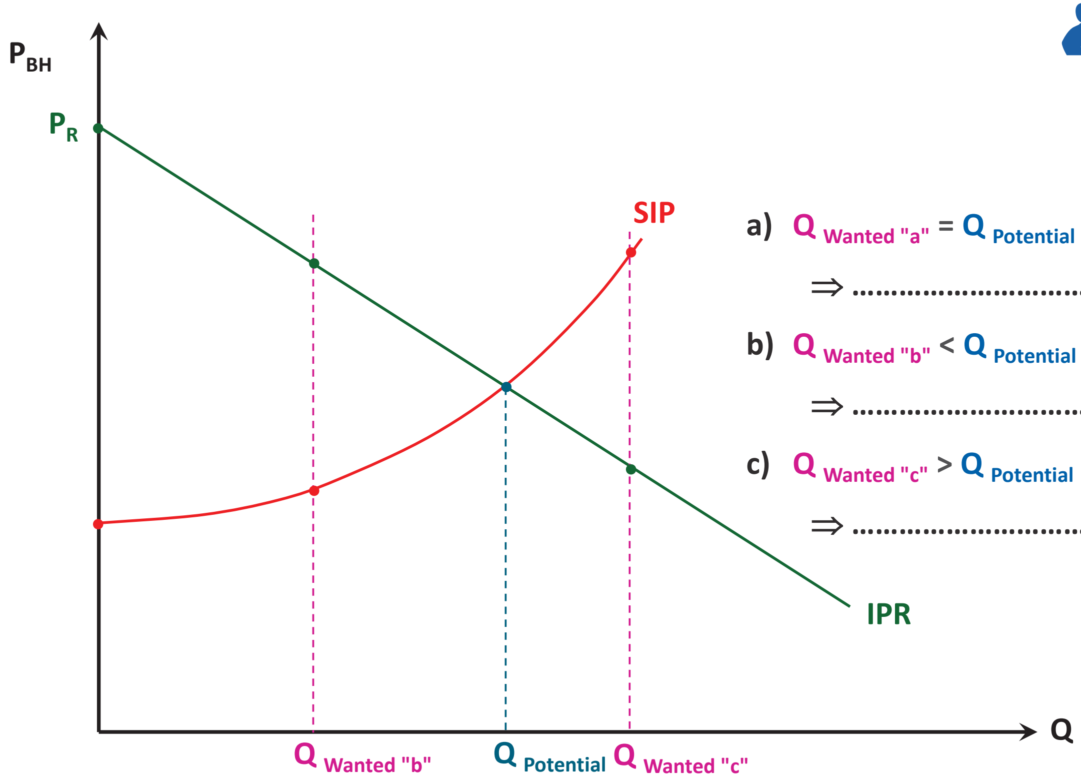
(Inflow & outflow)



IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

Q_{Wanted} & $Q_{\text{Potential}}$ in monophasic flow



a) $Q_{\text{Wanted "a"}} = Q_{\text{Potential}}$

$\Rightarrow$ ....?

b) $Q_{\text{Wanted "b"}} < Q_{\text{Potential}}$

$\Rightarrow$ ....?

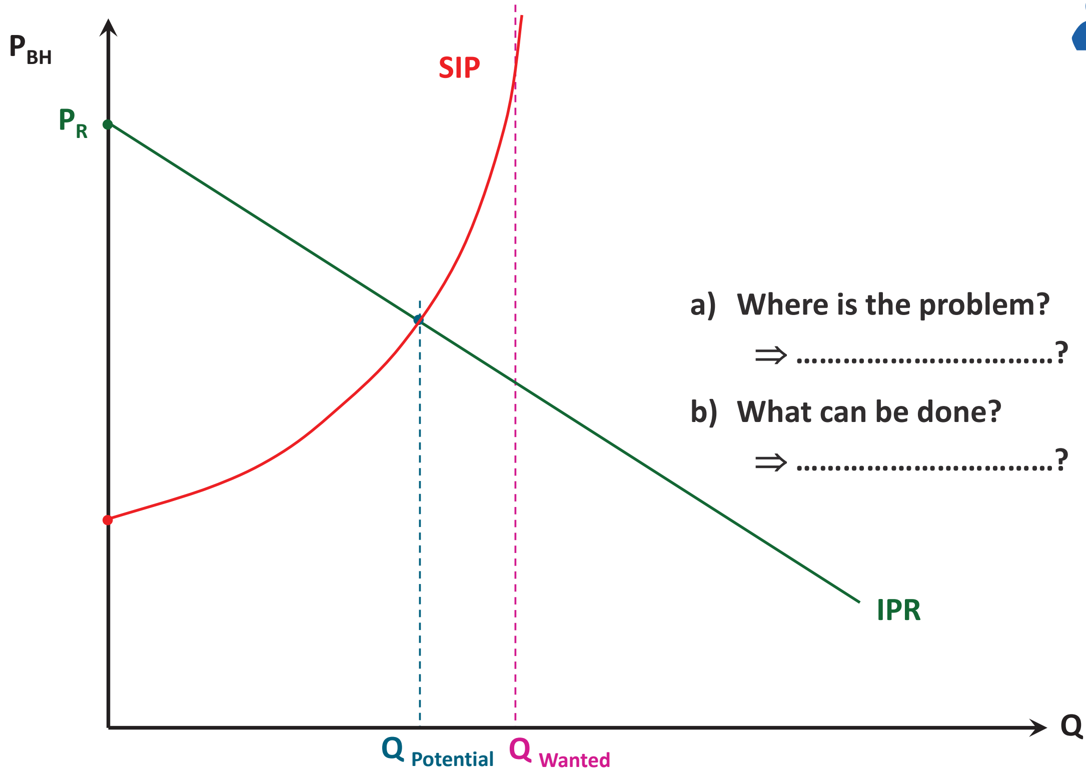
c) $Q_{\text{Wanted "c"}} > Q_{\text{Potential}}$

$\Rightarrow$ ....?

IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

What can be done if $Q_{Wanted} > Q_{Potential}$?: example 1



a) Where is the problem?

⇒ ....?

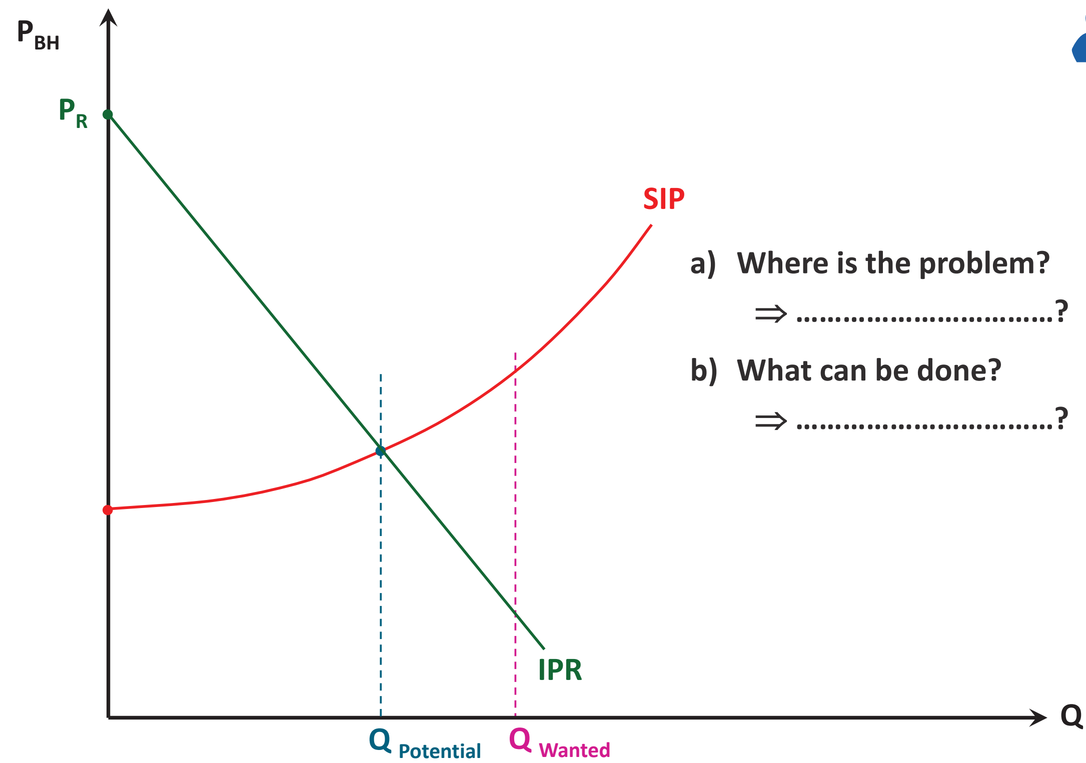
b) What can be done?

⇒ ....?

IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

What can be done if $Q_{wanted} > Q_{potential}$?: example 2



a) Where is the problem?

⇒ ....?

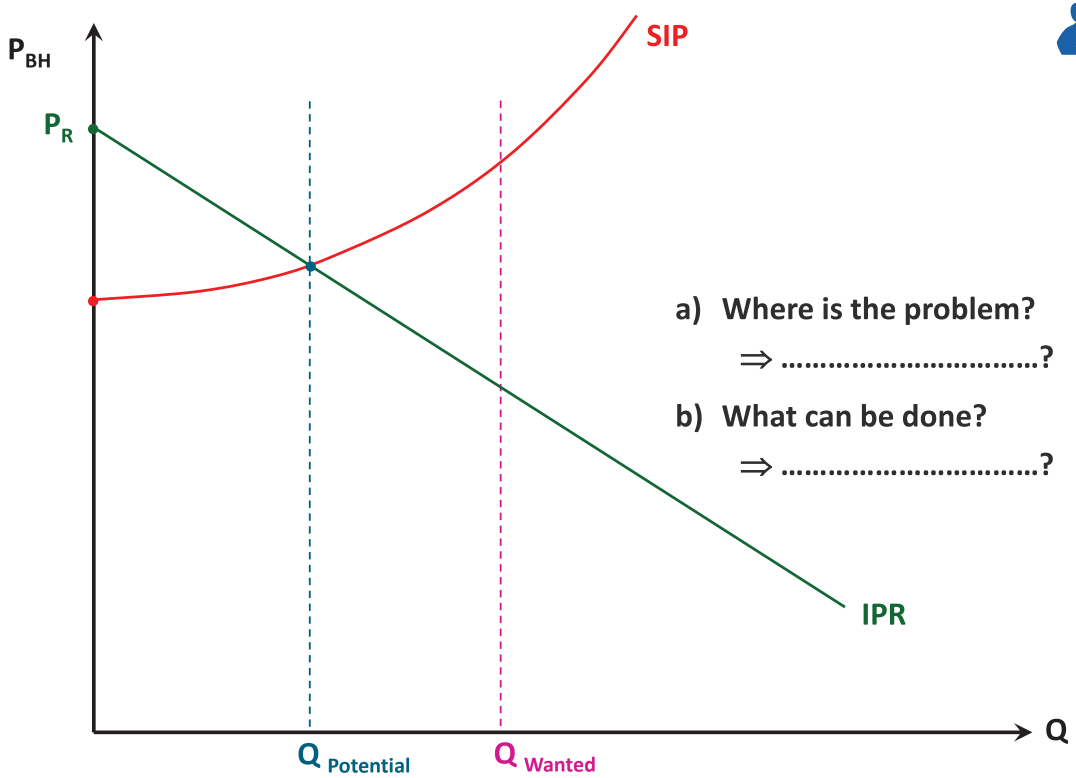
b) What can be done?

⇒ ....?

IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

What can be done if $Q_{wanted} > Q_{potential}$?: example 3



a) Where is the problem?

⇒ ....?

b) What can be done?

⇒ ....?

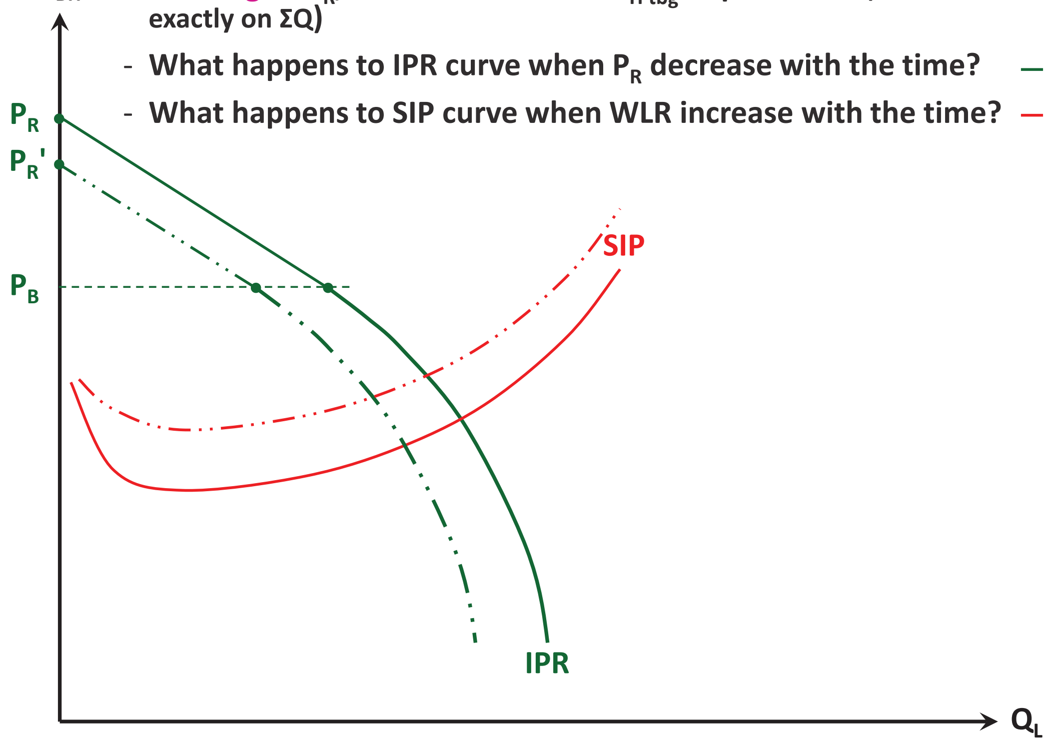
IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

Effect of the time on IPR & SIP curves

Don't forget: P_R, WLR & GLR and so $P_{H\ tbg}$ depend on T (or more exactly on ΣQ)

- What happens to IPR curve when P_R decrease with the time?
- What happens to SIP curve when WLR increase with the time?



IPR: Inflow performance response curve

SIP: System intake performance curve (also called "VLP": Vertical lift performance)

Well flow potential (SI field unit)

Exercise (1/4)

During a long duration well test on an exploration well equipped with a 2"3/8 tubing a flow rate of 200 m^3/d of anhydrous oil has been obtained under the following conditions:

- P_R = 395 bar at 4080 m vertical & P_{BH} = 375 bar
- P_{sep} = 25 bar & $\Delta P_{flowline} + \Delta P_{choke}$ = 20 bar
- $P_{H\ tbg}$ = 320 bar ($SG_{average}$ = 0.8) & ΔP_{tbg} = 10 bar

Questions (1/2) :

1) Calculate the practical or actual productivity index (PI_{actual})
   What do you think of it, knowing that the theoretical productivity index (PI_{th}) calculated by the reservoir department is equal to 45 $m^3 d^{-1} bar^{-1}$ ($m^3/d/bar$)
2) For the development wells to be drilled, what is the tubing diameter to be selected to be able to produce 400 m^3/d during 8 years under the following conditions (let consider that, on development wells, it will be possible after an appropriated treatment to obtain a PI_{actual} equal to 40 $m^3 d^{-1} bar^{-1}$):

   P_{sep} = 15 bar & $\Delta P_{flowline}$ = 5 bar

   No water produced (anhydrous production)

   reservoir pressure decline: 4 bar/year

   available tubing: 2"3/8, 2"7/8, 3"1/2, 4"1/2 (corresponding inside diameters: 2", 2"1/2, 3" & 4")

Well flow potential (SI field unit)

Exercise (2/4)

Questions (2/2) :

3) For the tubing diameter selected question 2, what is the liquid flow rate (oil + water) that it is possible to produce after these 8 years in the following conditions:

   water % in the liquid: 30 % & SG_{water} = 1.05

   PI_{liquid} equal to PI_{oil} that is to say: PI_{liquid} = 40 $m^3 d^{-1} bar^{-1}$
4) For the tubing diameter selected question 2, what is the liquid flow rate (oil + water) that it is possible to produce after these 8 years in the following conditions:

   water % in the liquid: 20 % & SG_{water} = 1.05

   PI_{liquid} equal to PI_{oil} that is to say: PI_{liquid} = 40 $m^3 d^{-1} bar^{-1}$
5) What can be done if we want, despite the presence of water, to continue to produce a liquid flow rate (oil + water) equal to 400 m^3/d during these 8 years?

Well flow potential (SI field unit)

Exercise (3/4)

Explo well	Development well (after 8 years, P_R decline = 4 bar/year)	
Q_o = 200 m^3/d PI_O = __ $m^3d^{-1}bar^{-1}$ Φ_{tubing} = 2"3/8	Q_O = 400 m^3/d & PI_0 = 40 $m^3d^{-1}bar^{-1}$ WLR = 0 Φ_{tubing} = ?	PI_L = 40 $m^3d^{-1}bar^{-1}$ & WLR = 0.30 SG_{water} = 1.05 Φ_{tubing} = Q_2 answer Q_L = ?
P_{sep} = ΔP_{fl} = ΔP_{choke} = ΔP_{tbg} = $P_{H\ tbg}$ =		
$P_{BH\ req}$ =		
P_R = - ΔP_R =		
$P_{BH\ avail}$ =		

Well flow potential (SI field unit)

Exercise (4/4)

Explo well	Development well (after 8 years, P_R decline = 4 bar/year)
Q_o = 200 m^3/d PI_O = __ $m^3d^{-1}bar^{-1}$ Φ_{tubing} = 2"3/8	PI_L = 40 $m^3d^{-1}bar^{-1}$ & WLR = 0.20 SG_{water} = 1.05 Φ_{tubing} = 3"1/2 Q_L = ?
P_{sep} = ΔP_{fl} = ΔP_{choke} = ΔP_{tbg} = $P_{H\ tbg}$ =	
$P_{BH\ req}$ =	
P_R = - ΔP_R =	
$P_{BH\ avail}$ =	

Extension of Pi notion

Main assumptions

IPR (Inflow Performance Relationship) according to J.V. VOGEL Solution-gas drive reservoir

- Reservoir shut-in pressure = Bubble pressure
- Circular reservoir, uniform and isotropic porous medium
- No skin effect
- Oil and gas at the same pressure and with constant properties (viscosity)
- No flow of water

Empirical equation

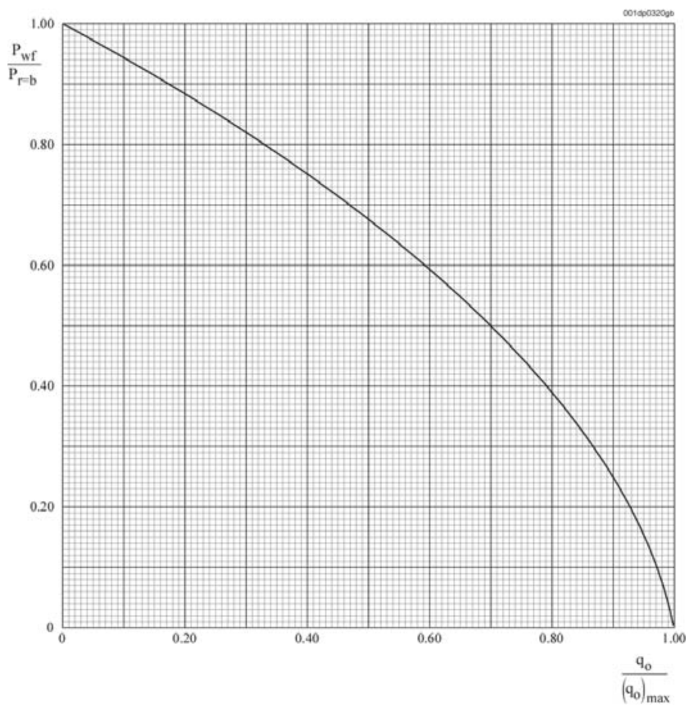
- **Empirical equation:**

$$\frac{q_o}{(q_o)_{max}} = 1 - 0.2\frac{P_{wf}}{P_{r=b}} - 0.8\left(\frac{P_{wf}}{P_{r=b}}\right)^2$$

- **Comments, limits:**
  - Deviation between anticipated flowrate and actual flowrate may be significant if:
    - Oil is very viscous
    - Reservoir shut-in pressure is greater than bubble pressure
    - There is some skin effect
  - Otherwise, deviation is smaller than 20 % and even 10 %
  - Approach still valid for the liquid flowrate (oil + water) if BSW < 10 %
  - Regularly make again a match point

IPR Curve

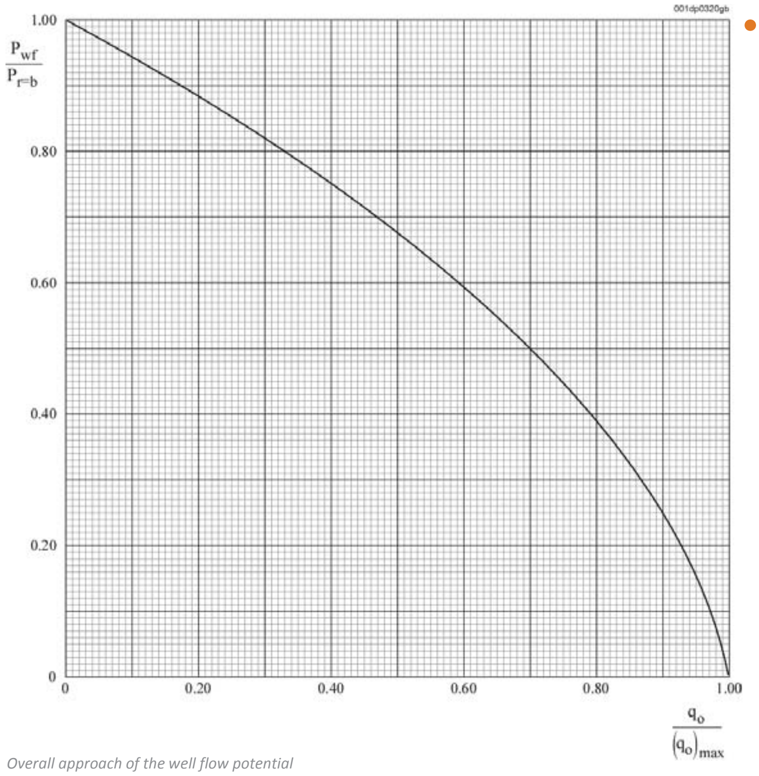
- **IPR curve: Curve $\frac{P_{wf}}{P_{r=b}}$ versus $\frac{q_o}{(q_o)_{max}}$**



- **How to use the IPR curve:**
  - To use this method, a match point must be known
  - Using the curve (or the equation), calculate $(q_o)_{max}$
  - From there, it is possible to calculate the flowrate for any bottomhole pressure

IPR Curve: example

- IPR curve: Curve $\frac{P_{wf}}{P_{r=b}}$ versus $\frac{q_o}{(q_o)_{max}}$



- **Example:**
  - A well is producing 120 m^3/d with a bottomhole pressure equal to 75 bar, reservoir pressure is 100 bar (with $P_r = P_{bubble}$ of oil)
  - What would be the flowrate for a bottomhole pressure equal to 25 bar ?

For $P_b < P_{wf} < P_r$ and for $P_{wf} < P_b < P_r$

Case where Pr > Pb according to D. PATTON and M. GOLAN

- **For $P_b < P_{wf} < P_r$:**
  - Monophasic flow, so:
    $q = PI\,(P_r - P_{wf})$
  - In particular, for $P_{wf} = P_b$:
    $q_b = PI\,(P_r - P_b)$ that is to say: $$q_b = q\,\frac{P_r - P_b}{P_r - P_{wf}}$$
- **For $P_{wf} < P_b < P_r$:**
  $q = q_b + q'$ with $$q_b = PI\left(P_r - P_b\right)$$

  So q' is defined from Vogel curve provided: $$q' = \left[q_{max} - q_b\right]\left[1 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right]$$

  - using P_b (and not P_r) in the ratio $\frac{P_{wf}}{P_b}$

  - using the ratio $$\frac{q - q_b}{q_{max} - q_b} = \frac{q'}{q_{max} - q_b}$$ instead of $\frac{q_o}{(q_o)_{max}}$

Synthesis

- If there is a match point for $P_{wf} > P_b$ and an other for $P_{wf} < P_b$:
  - q can be calculated for any P_{wf}
- If there is only one match point and provided we consider there is continuity between the two cases:
  - *if the match point is for $P_{wf} > P_b$:*

$$q_{max} = q_b + \frac{pq_{max} - q_b}{1.8} \qquad \text{(a)}$$

with pq_{max} = pseudo maximum flowrate

= flowrate for P_{wf} = 0 and PI at $P_{wf} > P_b$

that is to say:

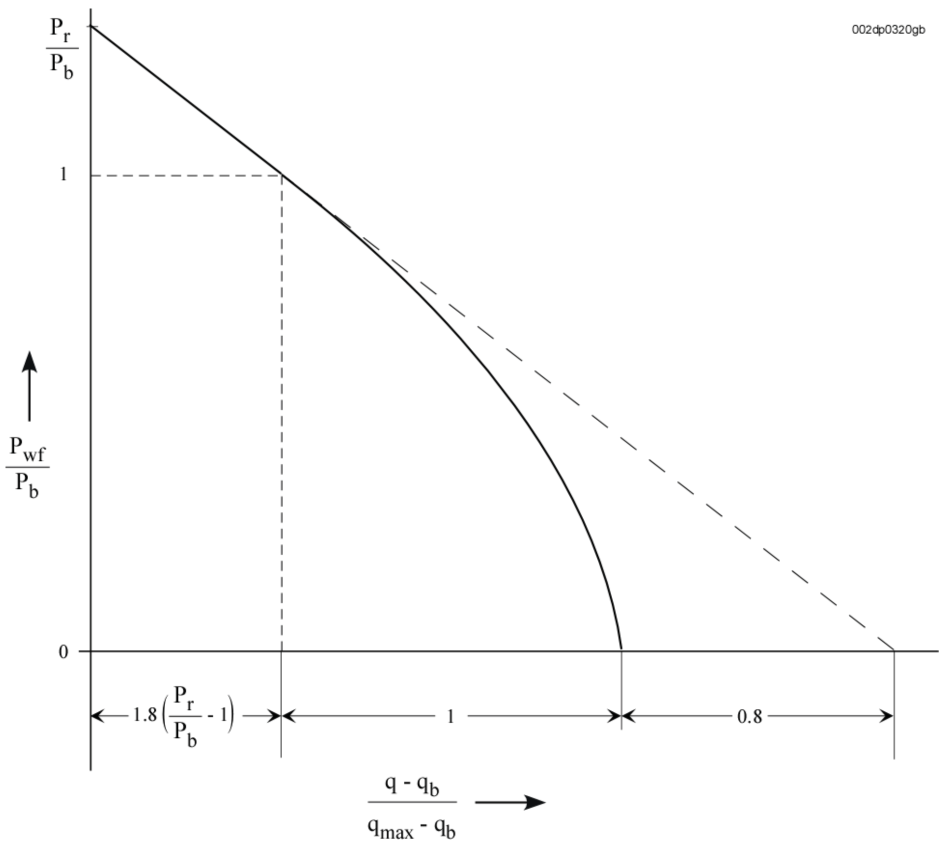
pq_{max} = PI x P_r or or $q_b \dfrac{P_r}{P_r - P_b}$ $\quad q \dfrac{P_r}{P_r - P_{wf}}$

  - *If the match point is for $P_{wf} < P_b$:*

$$q_{max} - q_b = q \Bigg/ \left[1.8\frac{P_r}{P_b} - 0.8 - 0.2\frac{P_{wf}}{P_b} - 0.8\left(\frac{P_{wf}}{P_b}\right)^2 \right] \qquad \text{(b)}$$

$$q_b = 1.8\left(\frac{P_r}{P_b} - 1\right)(q_{max} - q_b) \qquad \text{(c)}$$

Graphical representation



In practice

- If $P_{wf(m.p)} > P_b$

① $$\boxed{q_b} = q_{m.p} \frac{P_r - P_b}{P_r - P_{wf(m.p)}}$$

② $$pq_{max} = q_{m.p} \frac{P_r}{P_r - P_{wf(m.p)}}$$

③ $$q_{max} = q_b + \frac{pq_{max} - q_b}{1.8}$$ = ① + [②-①]/1.8 (a)

④ $\boxed{q_{max} - q_b}$ = ③ - ① = [②-①]/1.8

⑤ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ① + [R x ④]

In practice (cont)

- If $P_{wf(m.p)} < P_b$

⑥ $$\boxed{q_{max} - q_b} = \frac{q_{m.p}}{1.8\frac{P_r}{P_b} - 0.8 - 0.2\frac{P_{wf(m.p)}}{P_b} - 0.8\left(\frac{P_{wf(m.p)}}{P_b}\right)^2}$$ (b)

⑦ $$\boxed{q_b} = 1.8\left(\frac{P_r}{P_b} - 1\right)(q_{max} - q_b)$$ (c)

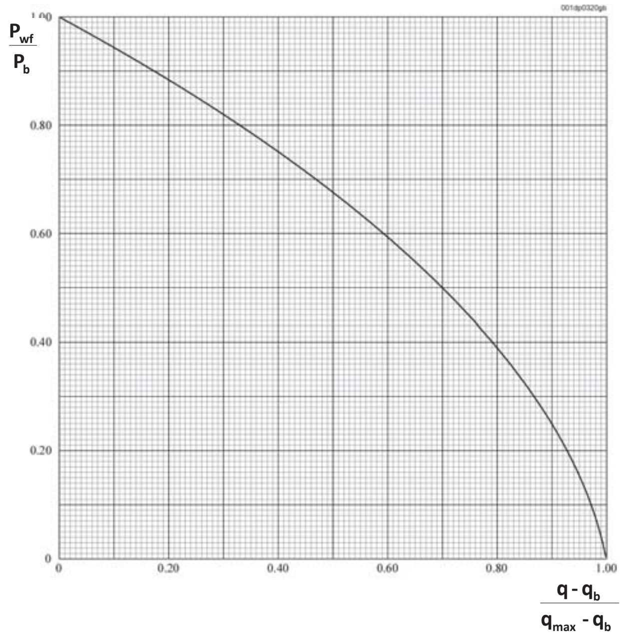
⑧ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ⑦ + [R x ⑥]

Determination of the IPR curve of a well

Exercise (1/6)

- Let consider two wells on the same reservoir (P_r = 100 bar, P_b = 50 bar)
  - well number 1 produce 120 m^3/d for P_{wf} = 75 bar
  - well number 2 produce 120 m^3/d for P_{wf} = 25 bar
- For each well, draw the curve "flowrate versus bottomhole pressure"



Determination of the IPR curve of a well

Exercise (2/6)

- If $P_{wf(m.p)} > P_b$:

① $\boxed{q_b} = q_{m.p} \dfrac{P_r - P_b}{P_r - P_{wf(m.p)}}$

② $pq_{max} = q_{m.p} \dfrac{P_r}{P_r - P_{wf(m.p)}}$

③ $q_{max} = q_b + \dfrac{pq_{max} - q_b}{1.8}$ = ① + [②-①]/1.8

④ $\boxed{q_{max} - q_b}$ = ③ - ① = [②-①]/1.8

⑤ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ① + [R x ④]

If $P_{wf(m.p)} < P_b$:

⑥ $\boxed{q_{max} - q_b} = \dfrac{q_{m.p}}{1.8\dfrac{P_r}{P_b} - 0.8 - 0.2\dfrac{P_{wf(m.p)}}{P_b} - 0.8\left(\dfrac{P_{wf(m.p)}}{P_b}\right)^2}$

⑦ $\boxed{q_b} = 1.8\left(\dfrac{P_r}{P_b} - 1\right)(q_{max} - q_b)$

⑧ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\frac{P_{wf}}{P_b}$	$R = \frac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ⑦ + [R x ⑥]

Determination of the IPR curve of a well

Exercise (3/6)

Well N° 1:

- The match point P_{wf} = 75 bar, q = 120 m^3/d is above the bubble pressure
- So: ① $\boxed{q_b} = q_{m.p} \dfrac{P_r - P_b}{P_r - P_{wf(m.p)}}$

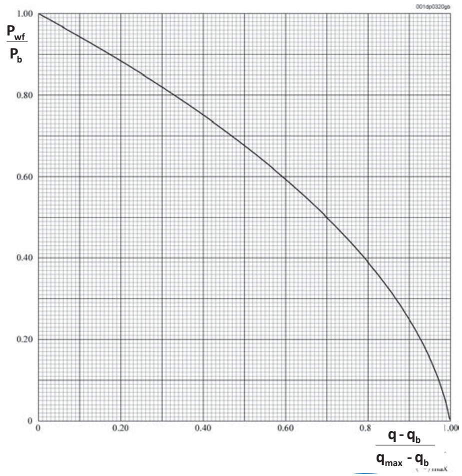
② $pq_{max} = q_{m.p} \dfrac{P_r}{P_r - P_{wf(m.p)}}$

③ $q_{max} = q_b + \dfrac{pq_{max} - q_b}{1.8}$ = ① + [②-①]/1.8

④ $\boxed{q_{max} - q_b}$ = ③ - ① = [②-①]/1.8

⑤ For $P_{wf} < P_b$:

For	Work out	Read on the chart	Work out
P_{wf}	$\dfrac{P_{wf}}{P_b}$	$R = \dfrac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$
50			
37.5			
25			
12.5			
0			



Determination of the IPR curve of a well

Exercise (4/6)

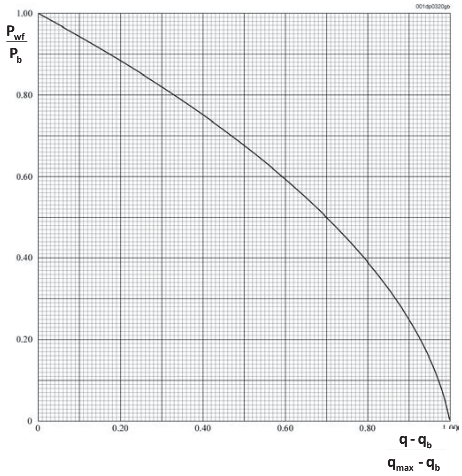
Well N° 2:

- The match point Pwf = 25 bar, q = 120 m3/d is below the bubble pressure
- So: ⑥ $\boxed{q_{max} - q_b} = \dfrac{q_{m.p}}{1.8\dfrac{P_r}{P_b} - 0.8 - 0.2\dfrac{P_{wf(m.p)}}{P_b} - 0.8\left(\dfrac{P_{wf(m.p)}}{P_b}\right)^2}$

⑦ $\boxed{q_b} = 1.8\left(\dfrac{P_r}{P_b} - 1\right)(q_{max} - q_b)$

⑧ For $P_{wf} < P_b$:

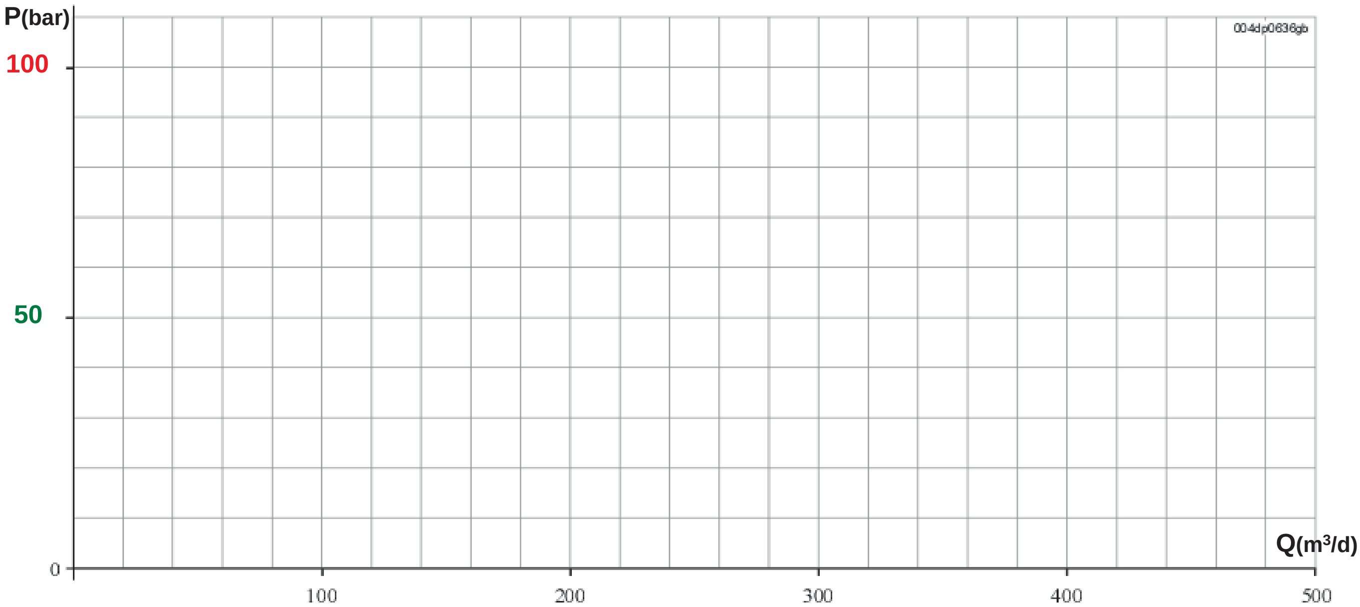
For	Work out	Read on the chart	Work out
P_{wf}	$\dfrac{P_{wf}}{P_b}$	$R = \dfrac{q - q_b}{q_{max} - q_b}$	$q = \boxed{q_b} + R\boxed{(q_{max} - q_b)}$ = ① + [R x ④]
50			
37.5			
25			
12.5			
0			



Determination of the IPR curve of a well

Exercise (5/6)

- **Graphical representation for well N° 1 and well N° 2:**



Reservoir-wellbore interface

(excluding "Wellbore treatments")

SUMMARY

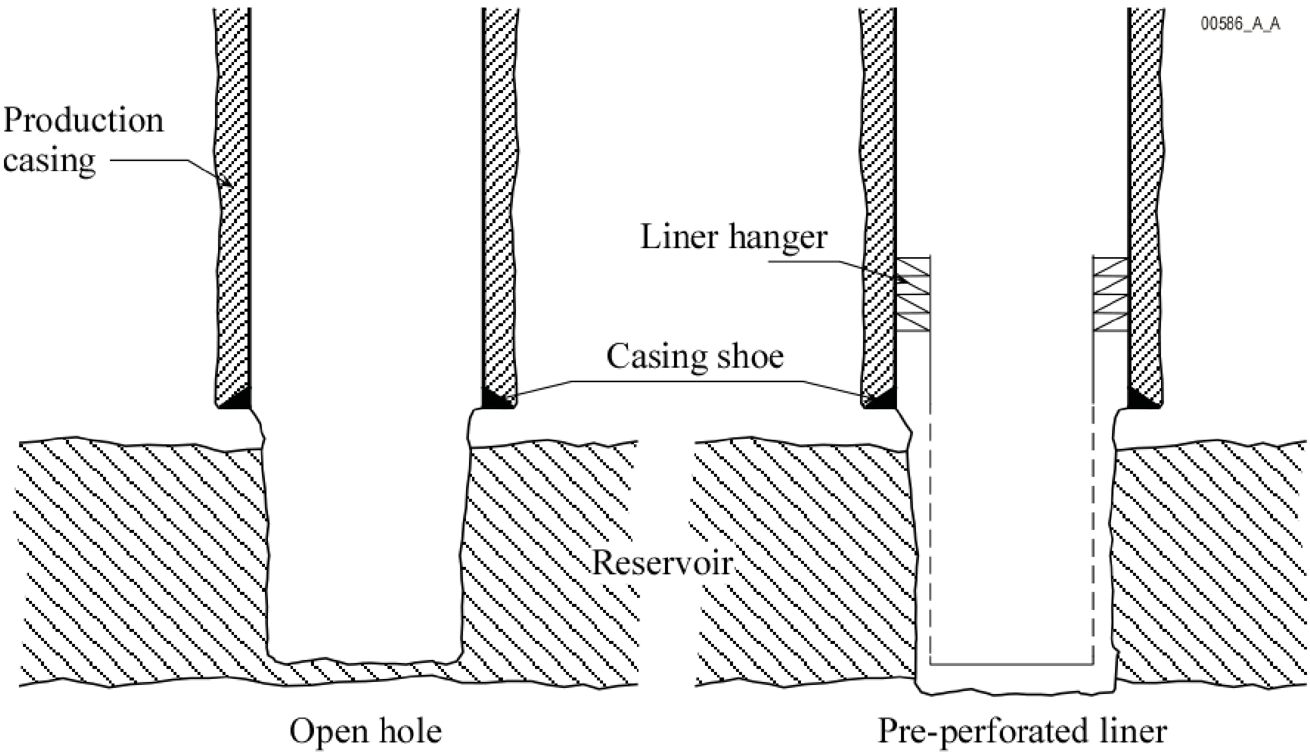
- Main configurations of the reservoir-wellbore interface (for memory)
- Drilling & casing the pay zone
- Evaluating the cement job
- Remedial cementing
- Perforating
- The special case of horizontal wells
- Skin: exercises

Main configurations of the reservoir-wellbore interface
(for memory)

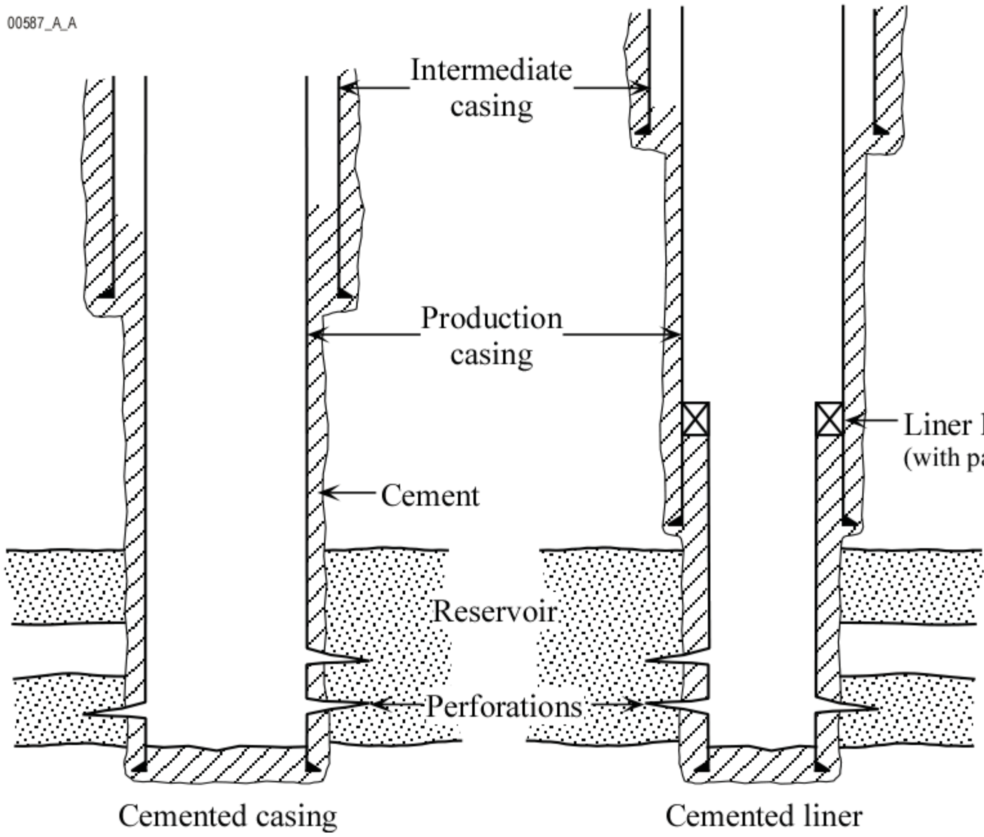
Main configurations of the reservoir-wellbore interface (for memory)

- **Basic requirements:**
  - Borehole wall stability
  - Selectivity of fluid or pay zone(s)
    (including selectivity of the zone to be treated, if any, and treatment efficiency)
  - Minimal restrictions along flow path, so well flow potential optimisation
- **Configuration of pay zone-borehole connection:**
  - Open hole completions*
  - Cased hole completions*

Open hole completion



Cased hole completion



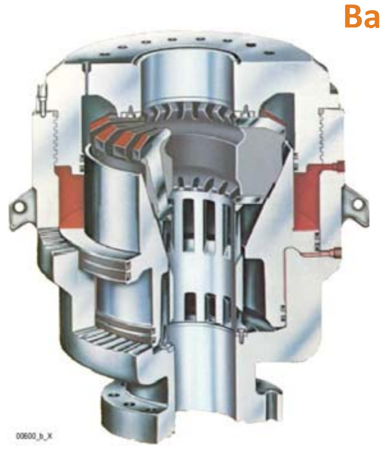
Drilling & casing the pay zone

Well safety

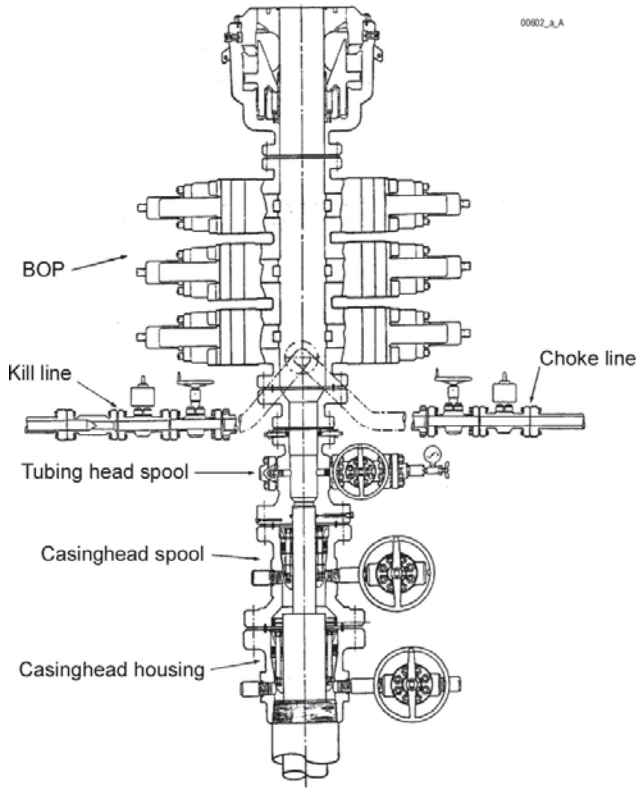
- Density of the fluid in the well
- Safety equipment*
- Operating precautions

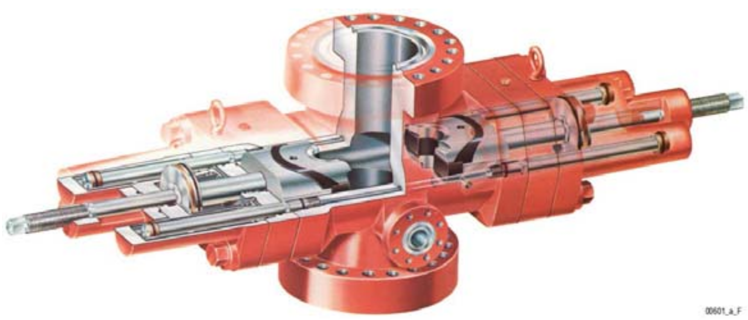
Safety equipment

Bag-type BOP



Wellhead for 6" drilling phase





Pipe rams BOP

Fluids used to drill in the pay zone

Constraints

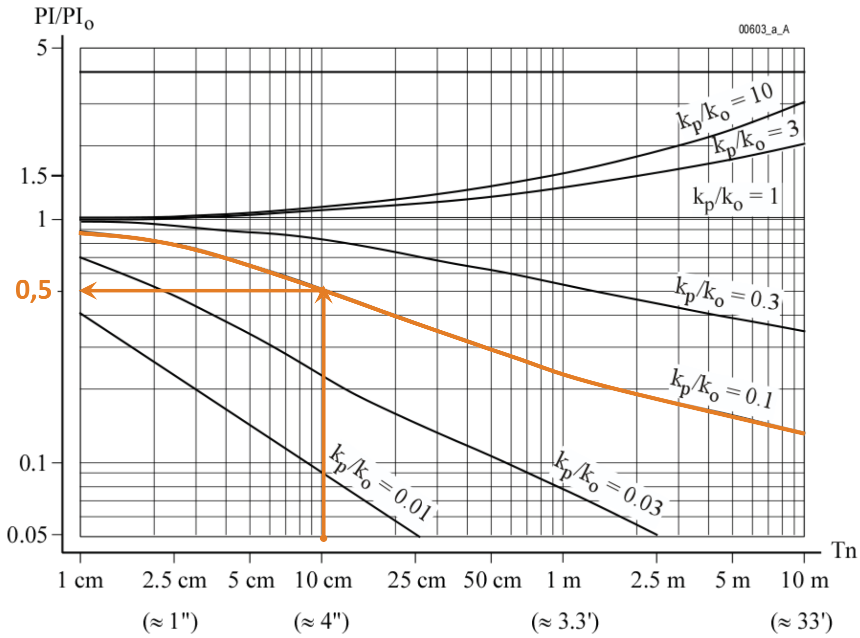
- **Safety constraints**
- **Drilling constraints**
- **Formation damage constraints:**
  - Influence on the productivity*
  - Restoration or prevention

⇒ **Required characteristics**
  - (see "Completion fluids")

Influence of near wellbore permeability on productivity index (in radial flow)

Borehole diameter : 8 " 1/2

Drainage radius : 500 m (≈ 1 700 ft)



Tn : Thickness of "plugged" zone from the borehole (8"1/2 drilling)

k_o : Natural permeability of the formation

k_p : Permeability of "plugged" zone

PI_o: Theoretical productivity index (without "plugged" zone)

PI : Actual productivity index (taking into account "plugged" zone)

Completion fluids

- **When ?**
  - Drilling in
  - Completion
  - Treatment
  - Workover
- **Required characteristics:**
  - Specific gravity ⇒ overpressure
  - Viscosity
  - Filtration rate
  - Compatibility
  - Stability
  - Preparation and handling
  - Price

Completion fluids (cont.)

- **Main completion fluids*:**
  - Foams — SG = 0.2 to 0.3
  - Oil base — SG = 0.8 to 1
  - Water base, solid free — SG = 1 to 2.3
  - Water base, solid laden — SG = 1 to 2.3

Main completion fluids

- **Foam:**
  - 0.20 to 0.30 dense foam
- **Oil base:**
  - 0.80 to 0.90 diesel or crude
  - 0.85 to 0.95 oil-base or inverted-emulsion mud
  - 0.85 to 1 direct emulsion mud

Main completion fluids (cont.)

- **Water base without solids(*):**
  - 1 to 1.03 water - seawater - brackish water
  - 1 to 1.16 fresh water + KCl
  - 1 to 1.20 fresh water + NaCl
  - 1 to 1.30 fresh water + $MgCl_2$
  - 1 to 1.40 fresh water + $CaCl_2$
  - 1.16 to 1.20 fresh water + KCl + NaCl
  - 1.20 to 1.40 fresh water + NaCl + $CaCl_2$
  - 1.20 to 1.51 fresh water + NaCl + NaBr
  - 1.40 to 1.70 fresh water + $CaCl_2$ + $CaBr_2$
  - 1.70 to 1.80 fresh water + $CaBr_2$
  - 1.80 to 2.30 fresh water + $CaBr_2$ + $ZnBr_2$

(*): Pay attention to the crystallisation point, especially with mixtures

Main completion fluids (cont.)

- **Water base plus solids:**
  - 1 to 1.70 fresh water + $CaCO_3$
  - 1 to 1.80 fresh water + $FeCO_3$ (siderite)
  - 1 to 1.80 drilling mud + $CaCO_3$ or $FeCO_3$
  - 1 to 2.30 drilling mud + barite
  - 1 ~~to 2.30 fresh water + resins~~
  - 1 to 2.30 oil-base mud or
    inverted or direct emulsion mud

Additives

- Viscosifiers
- Defoamer
- Fluid-loss control agent
- Emulsifiers (mud containing oil, etc.)
- Weighting material
- Anticorrosion (bactericides, antioxidants)

Annulus fluids

- **Functions and requirements:**
  - To protect the casing $\Rightarrow$ "Non corrosive" fluids
  - No settling $\Rightarrow$ Free solid fluids
  - To decrease efforts on packer, casing, tubing
  - Help to well control
- **Main fluids (depending on the required specific gravity):**
  - Brine
  - Water
  - Diesel oil
  - Oil
- **Protection against corrosion:**
  - High pH (> 9.5)
  - Oxygen scavener
  - Film-forming and antibacterial products:
    - Problem of compability between products

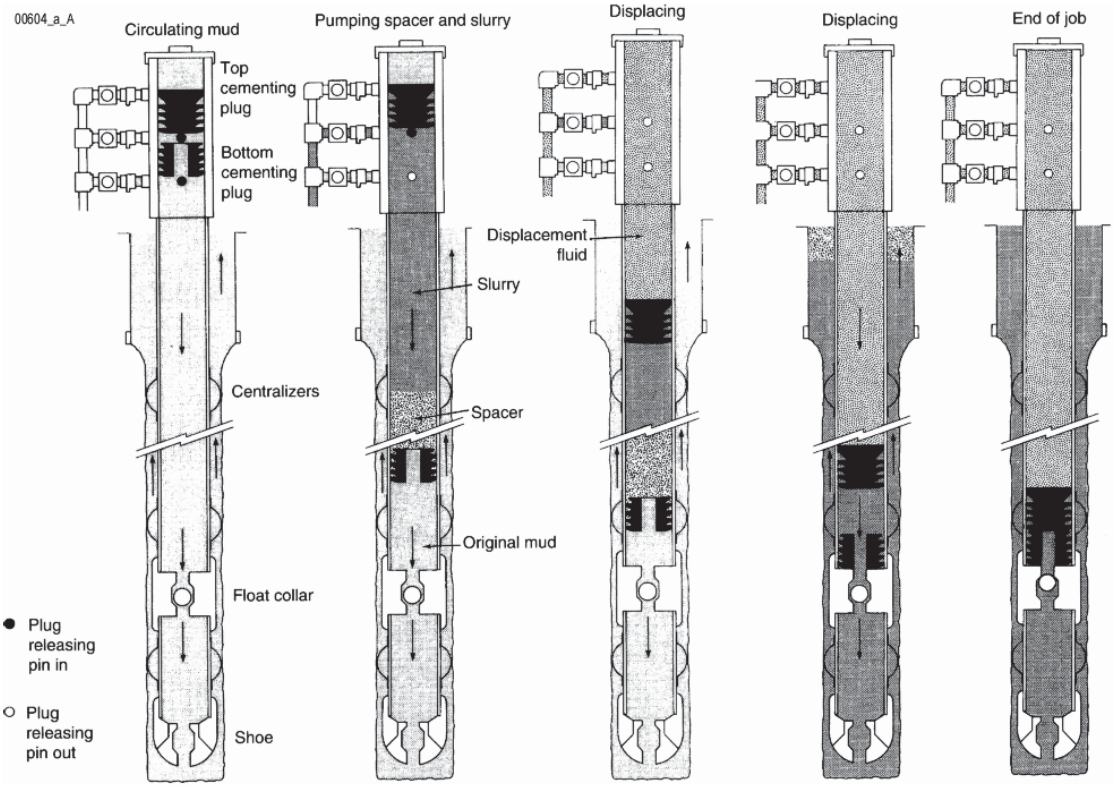
Drilling and casing diameters

- **Effect on productivity index:**
  - Small impact of drilling diameter on PI (unless sand control process)
- **Considerations relative to equipment:**
  - What is important is to have the place required for the production equipment

Main objectives of a primary cementing

- **Selectivity**
- **Borehole holding**
- **Protection of the casing**

Primary casing cementing procedure



Evaluating the cement job

Major flaws encountered after primary cementing

- **Inadequate filling:**
  - Incorrect estimate of volume (caved hole, ...)
  - losses during displacement
  - Unexpected setting
- **Inadequate seal and/or strength:**
  - Insufficient distance between float collar and shoe
  - Excessive displacement
  - Incomplete displacement of the mud by the slurry (centring, pumping rate, spacer, caved hole, ...)
  - Gas kick
  - No or partially setting
  - Poor quality slurry
  - Deterioration with time

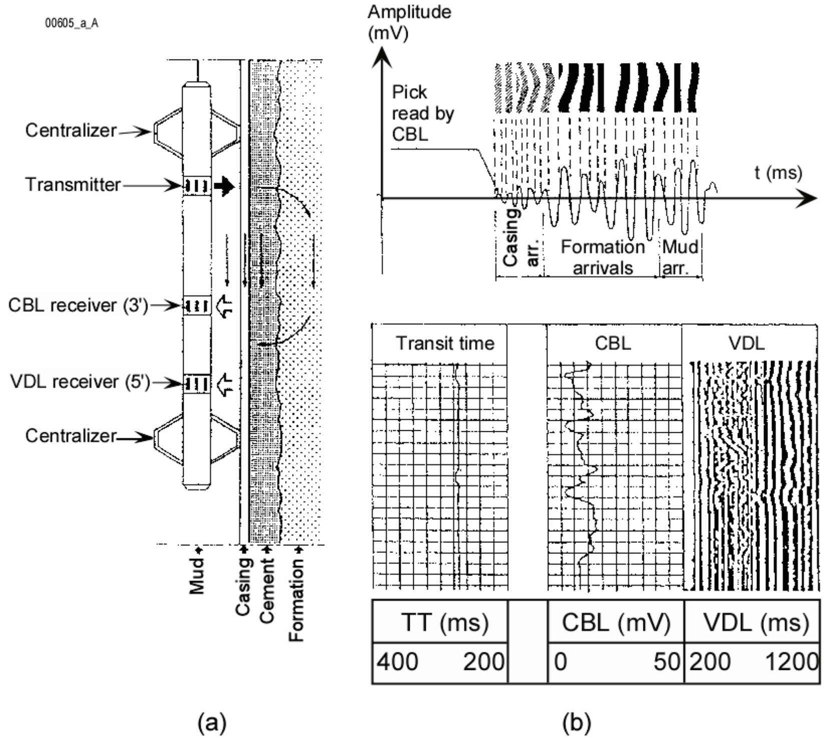
Evaluating methods

- **Sign during cement job:**
  - Irregularities
- **Direct evaluation:**
  - Pressure test
  - Negative pressure test
- **Indirect evaluation:**
  - Temperature logs
  - Acoustic logs:
    - CBL-VDL (Cement Bond Log – Variable Density Log)
    - CET (Cement Evaluation Tool)
    - USIT (UltraSonic Imager Tool)

CBL-VDL

- **CBL-VDL*:**
  - Low-frequency acoustic wave (20 khz)
  - Vertical path (3 to 5 ft)
  - CBL = Amplitude and transit time of the 1st wave
  - VDL = Complete wave train (positive peaks)
  - Good cement job if CBL low and VDL "formation"
  - Poor cement job if CBL strong and VDL "casing"

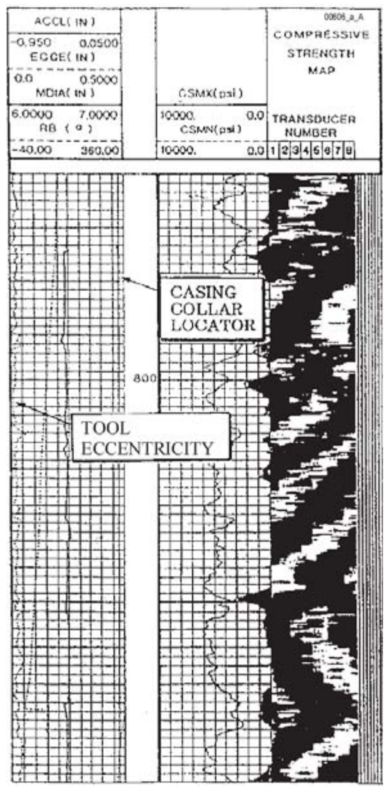
  Be careful:
  - A large number of parameters affect measurements



Principle of the CBL - VDL & standard presentation of a recording

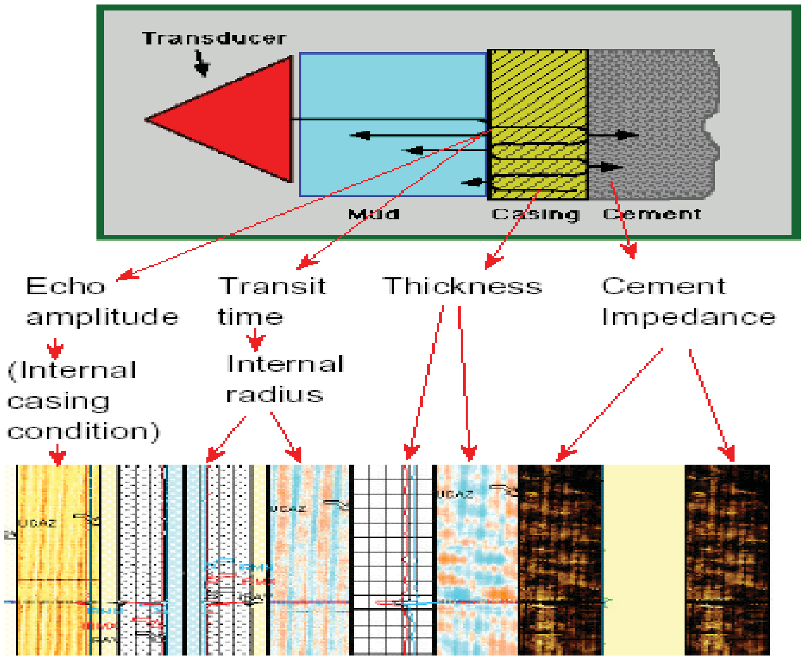
CET

- **CET*:**
  - High-frequency acoustic wave (500 khz)
  - Measure of the casing radial (horizontal) resonance according 8 directions
  - Provides :
    - Average casing diameter and ovalisation
    - Mini and maxi compressive strength of the cement
    - "Image" of the cement sheath
  - Good cement job if quick attenuation
    $\Rightarrow$ black stripe
  - Poor cement job if slow attenuation
    $\Rightarrow$ white stripe

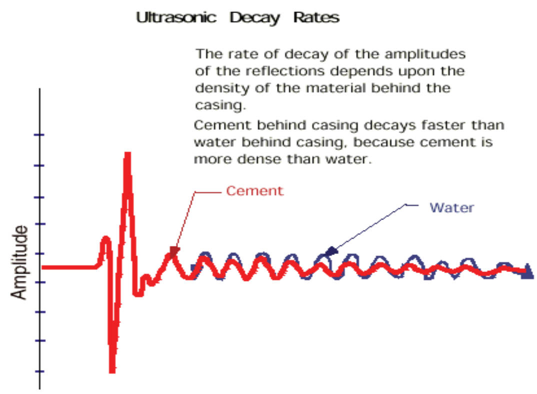


Standard representation of a CET recording

Ultrasonic reflection principles

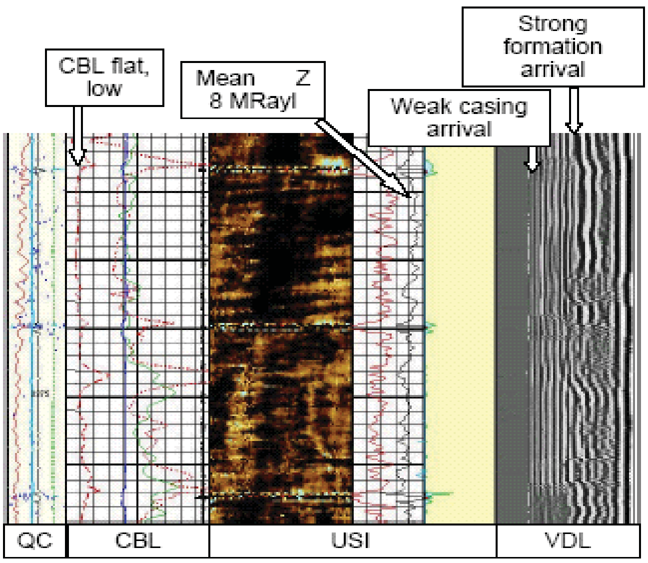


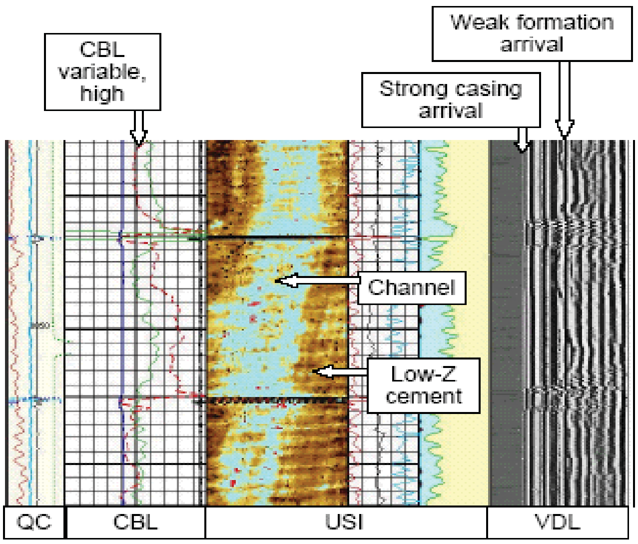
Ultrasonic decay rate



Acoustic Impedance of material in contact with casing

Good Cement





Mud channel & contaminated cement

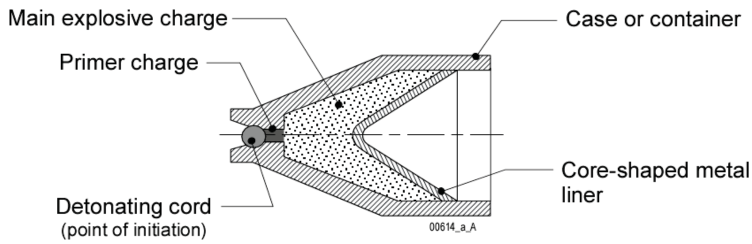
Perforating

Summary

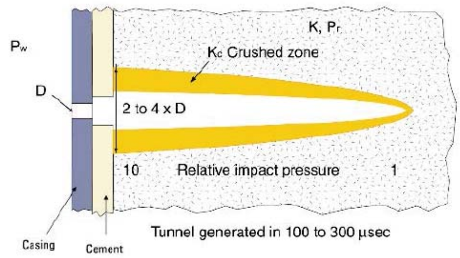
- Objective & Existing processes
- Perforating methods & Corresponding types of guns
- Shaped charges
- Main parameters affecting the productivity of a zone produced by perforating
- Specific points in the operating technique

Objective & existing processes

- **Objective:**
  - To re-establish the best possible connection between the pay zone and the borehole
- **Existing processes:**
  - Bullet
  - Mechanical perforator
  - Hydraulic perforator
  - . . .
  - Shaped charges*



Shaped charge

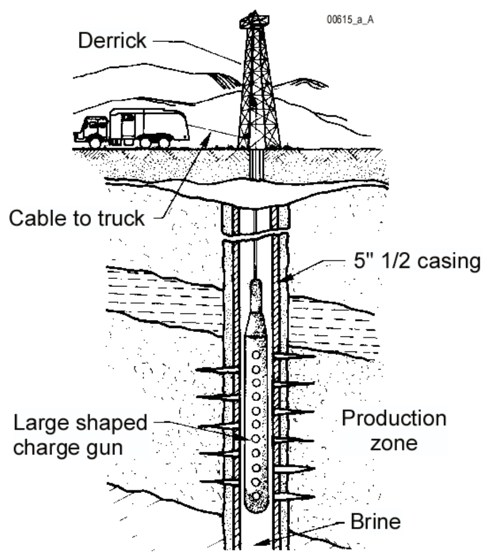


Perforation tunnel & Crushed zone

Note: - **Pay attention to productivity***
- **Efficiency function of gun selection & perforating method**

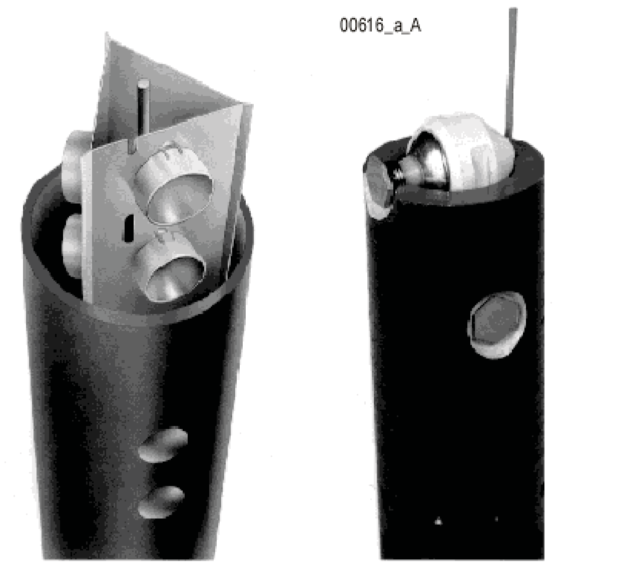
Overbalanced pressure perforating before equipment: Method

- **Principle:**
  - Before equipment installation
  - Well full of completion fluid
- **Advantages (see also advantages of corresponding carriers):**
  - Good penetration
  - Multiple shot directions
- **Drawbacks (see also drawbacks of corresponding carriers):**
  - Overbalanced conditions
    ⇒ plugging
  - Subsequent cleaning hard to do
  - (Safety condition not as good for further operations)



Overbalanced pressure perforating before equipment: Corresponding carriers

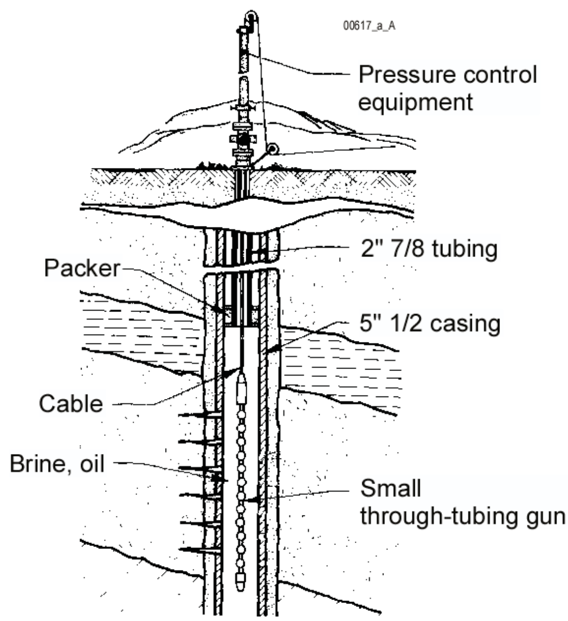
- **Retrievable casing guns (run with an electrical cable):**
  - Leakproof guns
  - Run with electric cable
  - Shot density: 4 (to 12 and more) SPF
  - Phasing: 90° - 120° - 180°
  - Unit length: 6 to 11 ft
  - Can be assembled together
- **Advantages:**
  - Good reliability
  - Charges isolated from fluid and pressure
  - No debris in the well
  - Selective firing
  - No casing deformation
- **Drawbacks:**
  - Limited length run in at one time
  - Difficult run in highly deviated well



High shot density Standard density

Underbalanced pressure perforating after equipment: Method

- **Principle:**
  - After equipment installation, Christmas tree included
  - Well full of "light" liquid
- **Advantages (see also advantages of corresponding carriers):**
  - No or reduced plugging
  - Well equipment in place (safety)
- **Drawbacks (see also drawbacks of corresponding carriers):**
  - Small gun ⇒ small shaped charges (*) ⇒ smaller penetration (*)
  - Only one shot direction (depending the gun size) (*)
  - Leave debris in the well (if semi or fully expendable carriers)
  - Mind out excessive ΔP:
    - reservoir deconsolidation
    - carrier possibly dragged up
  - (*) Except for pivot gun

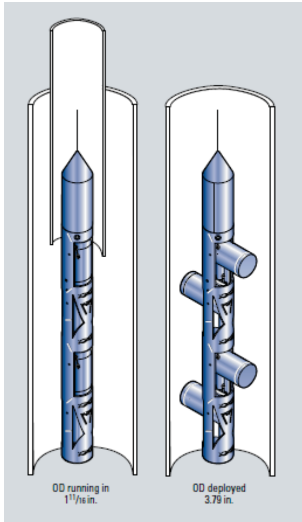


Underbalanced pressure perforating after equipment:

Corresponding carriers

- **Retrievable through tubing guns*** **(run with an electrical cable):**
  - Refer to "Retrievable casing gun"
  - But:
    - Small charge ⇒ small or very small penetration (except for "pivot guns")
    - Gun expansion ⇒ risk to get stuck when pulling up
- **Semi* or fully expendable carriers** **(run with an electrical cable):**
  - Thinner carrier ⇒ charges a little bigger
  - But:
    - No selective firing
    - Leave debris in the well
    - Casing and cement sheath possibly damaged
    - More restricted in pressure and temperature
- **And, for both of them:**
  - Difficult run in in highly deviated well

Scallop gun



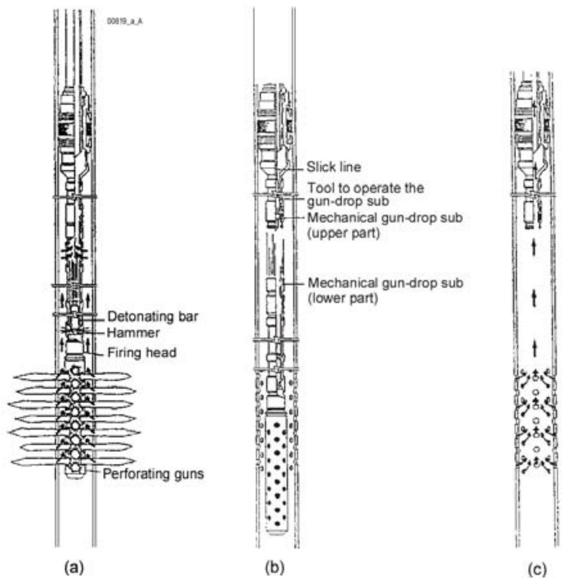
Pivot gun

Enerjet

TCP perforating

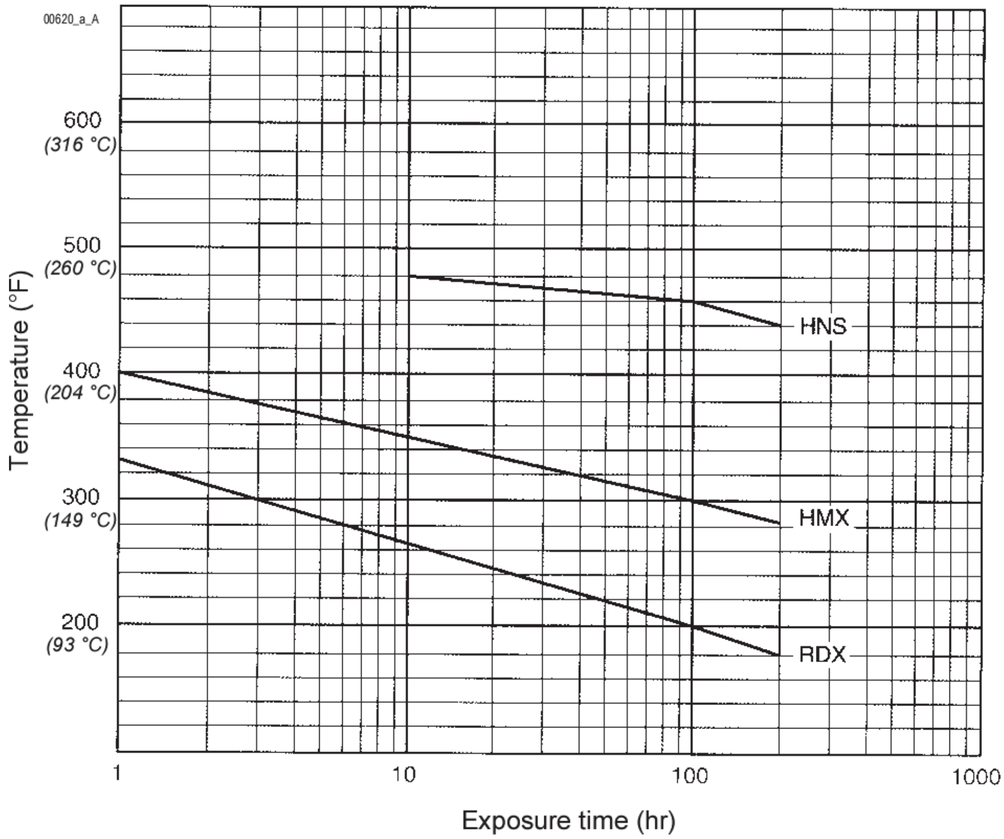
(TCP = Tubing Conveyed Perforator)

- **Principle*:**
  - Guns run in directly with the tubing
  - Underbalanced pressure when fired
- **Advantages:**
  - Good penetration
  - No or reduced plugging
  - Perforating in one single operation:
    - Very long stretch of casing
    - High shot density
  - No problem in highly deviated well
- **Drawbacks:**
  - "Trash dump" has to be drilled
    or
    No access opposite the pay zone for wireline jobs
  - Charges performances decrease with temperature and time*
  - Impossible to check that all the charges have been fired
  - If "misfire":
    - Time-consuming
    - Safety problems



Basic TCP procedure

Time-temperature ratings for explosives



TCP perforating

(TCP = Tubing Conveyed Perforator)

- **In practice, mainly used with a temporary string:**
  - To perforate a long stretch of casing
  - When gravel packing:
    - Large diameter perforations
    - High shot density
  - To perform perforations and DST (Drill Test Stem) in one single operation:
    - Gain in safety
    - Gain in time
    - but:
    - Risk to damage the recorders

TCP perforating

(TCP = Tubing Conveyed Perforator)

- **Specific equipment:**
  - Guns: cf "retrievable guns"
  - Firing head
  - Gun release system(*)
  - Circulating devices (with or without a rupture disk)
  - Isolation device
  - Shock absorbers
  - Depth reference
- ***: equipment actuated:**
  - Mechanically
  - Hydraulically
  - Electrically
  - Automatically

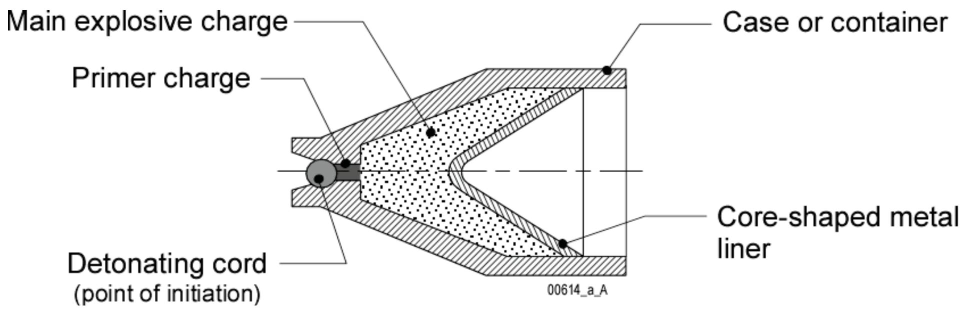
Choice of the method

Trade-off between:

- **Well constraints:**
  - Plugging (whether or not?, thickness of the damage zone)
  - Risk of sand intrusion
  - Type of effluents
  - Reservoir characteristics
  - State of the well (casing, cement job)
  - Safety
- **And optimum perforating conditions(*) :**
  - Underbalanced shooting
  - Clean fluid in the well
  - Large-diameter perforator
  - High-performance charges
  - Clearing as soon as possible after shooting
- ***: Conditions which are not necessarily compatible with one another**

Shaped charges principle

- **Five components:**



Note:
- **Velocity of jet of gas: 7000 m/s (20, 000 ft/s)**
- **Pressure on target: 30,000 MPa (5 . 10^6 psi)**
- **Velocity of slug: 300 to 1000 m/s (1000 to 3000 ft/s)**

- **Perforation dimensions dependent on:**
  - Amount of explosive load
  - Type and angle of the metal cone
  - Distance "shape charge - target" (stand-off)
  - Density of the target

Safety

- **Electrical system check before perforating**
- **Basic safety (1/2):**
  - Perforation not performed:
    - During storms
    - At night, except if…
  - If perforating carried out with "overbalanced pressure before equipment installation":
    - Completion fluid
    - Drilling BOPs
    - High-pressure pump connected to the well
    - Monitoring of the well stability when:
      - Firing
      - Pulling out

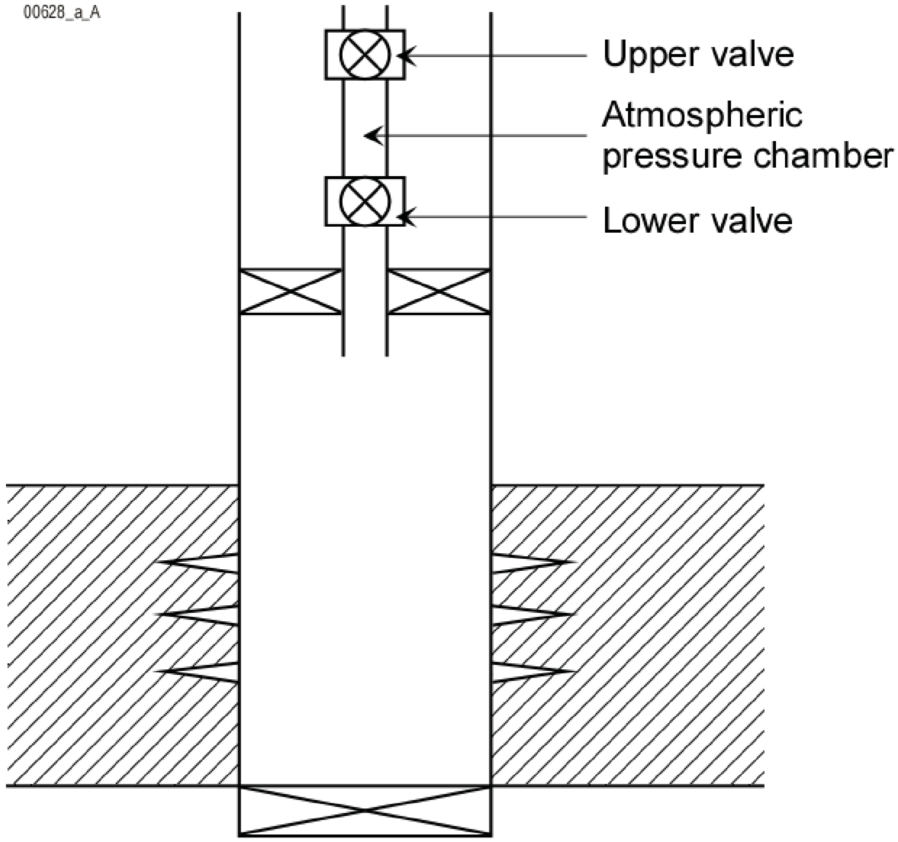
Safety (cont.)

- **Basic safety (2/2):**
  - If perforating carried out with "underbalanced pressure after equipment installations":
    - Production wellhead and lubricator
    - Monitoring of the wellhead pressure when:
      - Firing
      - Pulling out
- **Further precautions when loading, starting to run in and concluding pulling out:**
  - All radio broad casting cutted-off (depending the type of fire system)
  - Non-essential personnel out of the way
  - Nobody in the line of fire (if it is possible)
  - Extra care when pulling out if misfire

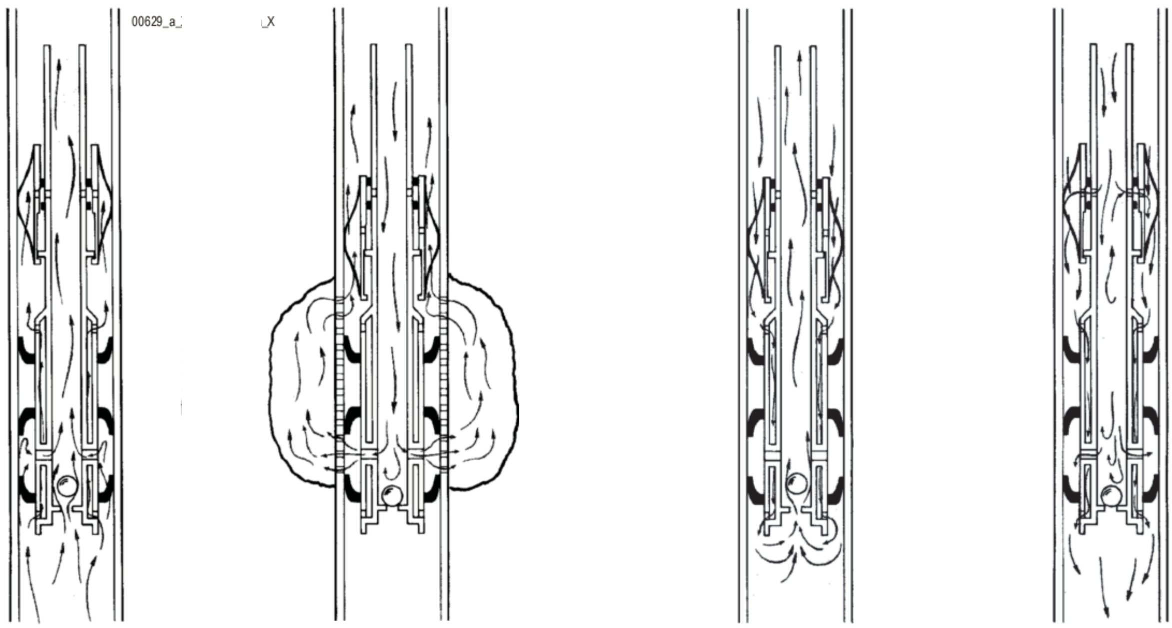
Other operating points

- **Perforation depth adjustment:**
  - By reference to logs
- **Cleaning the perforations:**
  - Well clearing
  - Back surging*
  - Washing tool*
  - Acid washing

Back surging



Washing tool



(a)	(b)	(c)	(d)
Running in	**Washing perforations**	**Reversing off bottom**	**Coming out of hole**

Other operating points (cont.)

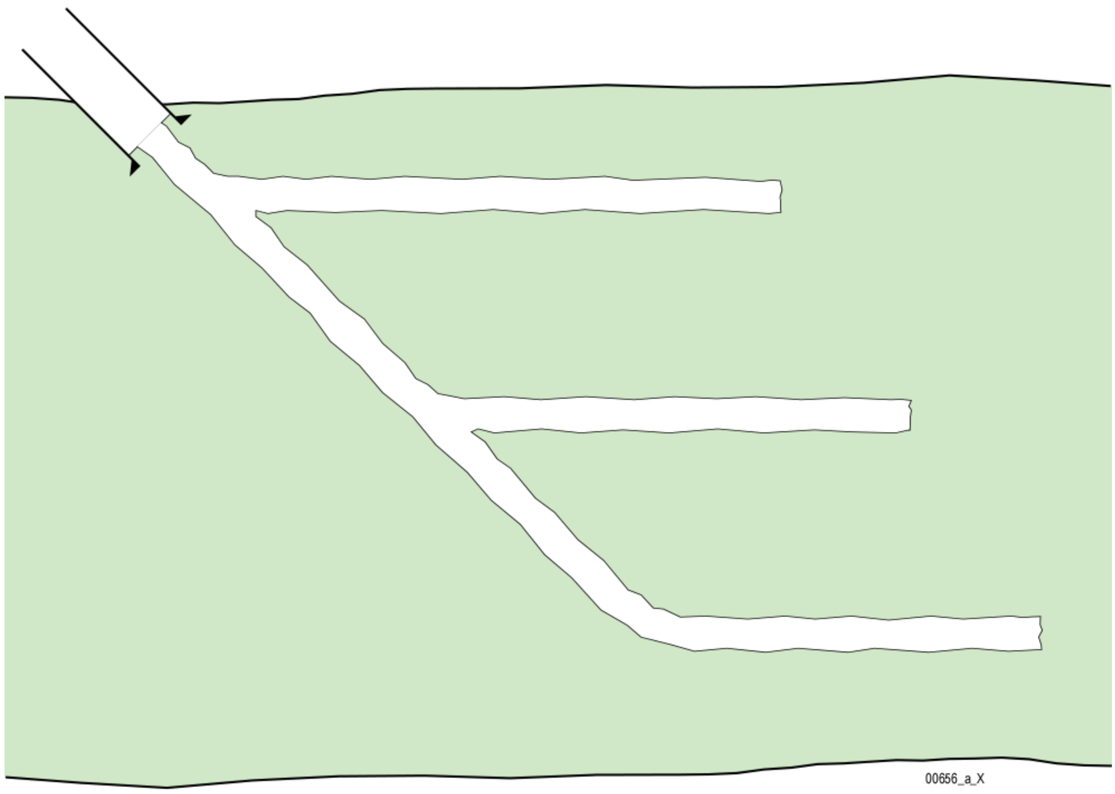
- **Monitoring the result:**
  - Flow rate measurement (test separator)
  - Well testing
  - Production logging

The special case of horizontal wells

Advantages in producing reservoirs

- **For a low permeability formation:**
  - Advantages in comparison with an hydraulic frac:
    - Horizontal extension
    - Frac residual permeability
    - Control of the orientation
    - No problem of vertical extension (when interface)
    - $\Rightarrow$ Improved productivity
  - Drawbacks if:
    - Thick reservoir
    - Low vertical/horizontal permeability ratio
    - But multidrains*

Single layer and direction multidrains well



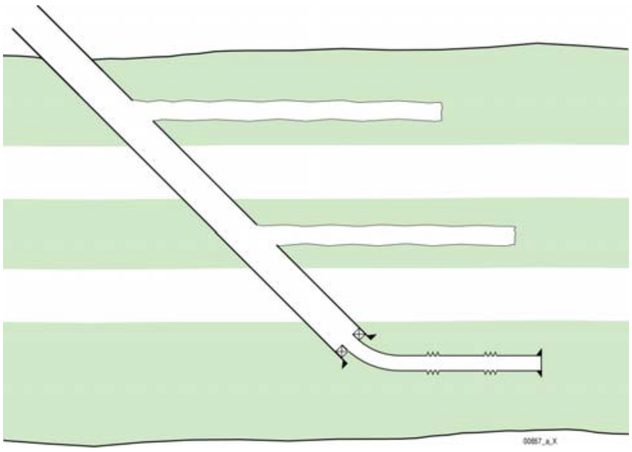
Advantages in producing reservoirs

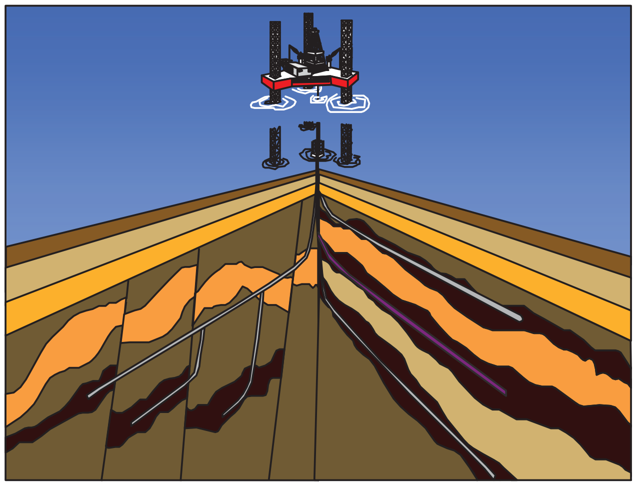
- **For a thin formation:**
  - Horizontal drain length versus vertical drain length
- **For a plugged formation:**
  - (Secondary consequence)
- **With regard to turbulence effect**
- **With regard to critical flowrate (coning):**
  - Productivity index
  - Drain/interface position

Advantages in producing reservoirs

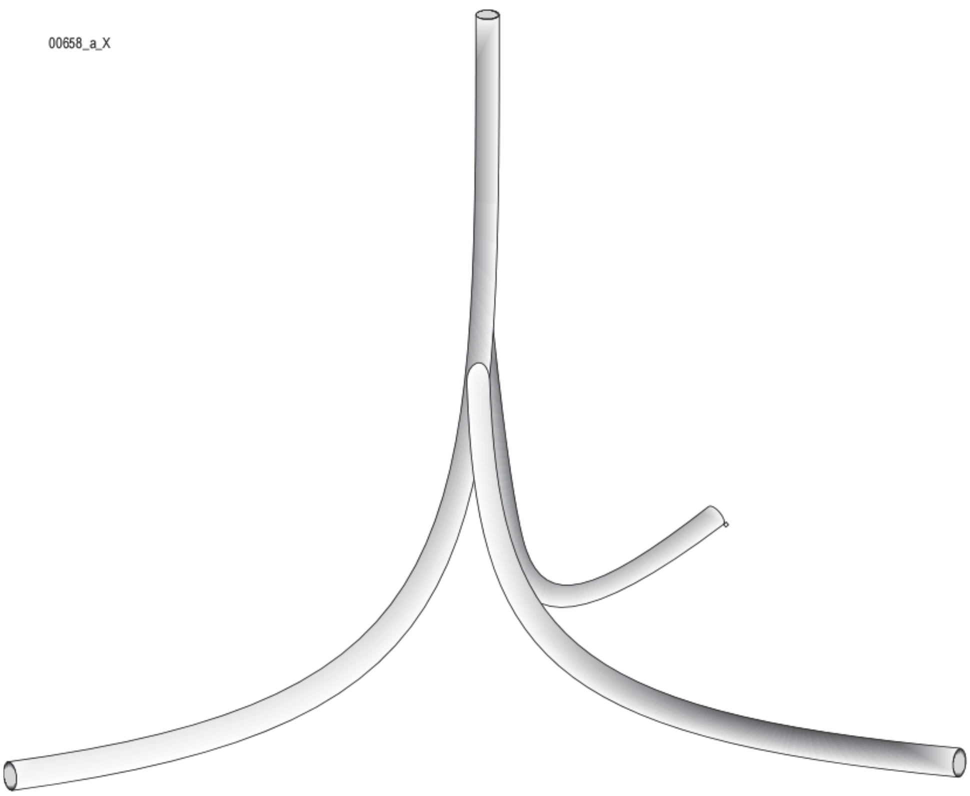
- **For an insufficiently consolidated formation:**
  - Fluid velocity
  - Accumulation capacity
  - Screen plugging
- **For a multilayers reservoir*:**
- **For a naturally fractured, heterogeneous formation, etc.:**
  - Fractures interception, etc.
- **With regard to recovery:**
  - Drainage area*
  - Secondary recovery:
    - Injection capacity
    - Injection distribution

Multi layers multidrains well





Single layer and multidirectional multidrains well



Advantages in producing reservoirs

- **Generally speaking, if appropriate conditions:**
  - Faster recovery rate

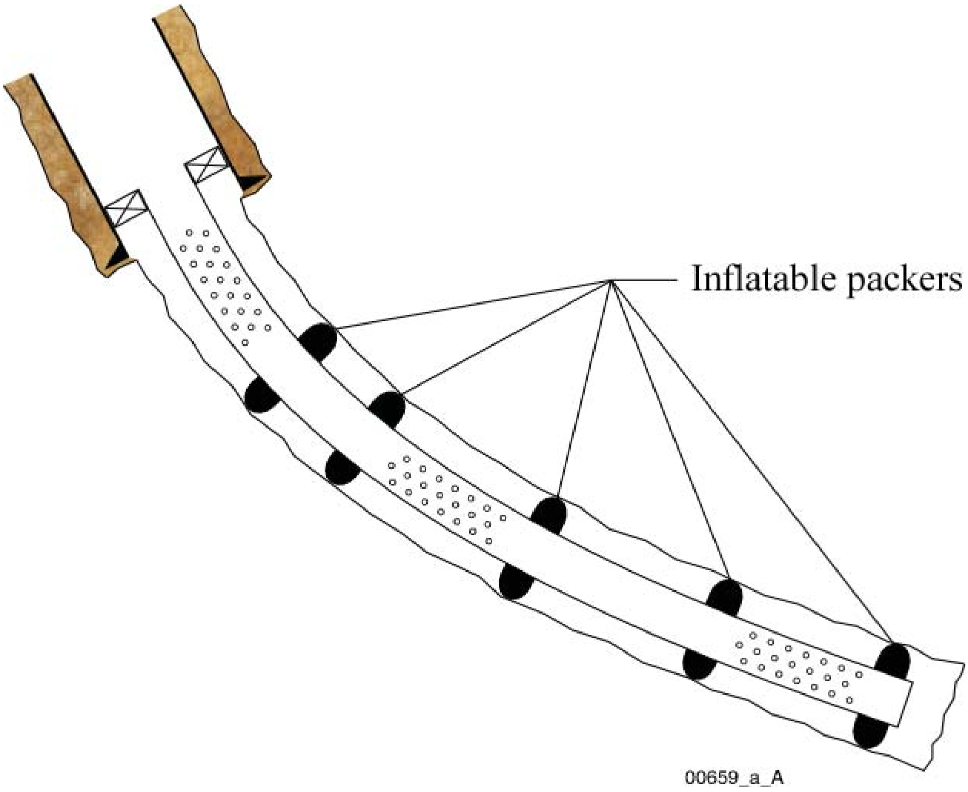
  and/or
  - Fewer wells

  and/or
  - Help to solve certain production problems
    - Lower differential pressure (P_R - P_{BH})
    - Increased recovery rate

Problems specific to the payzone-borehole connection

- **Configuration:**
  - Basic configurations:
    - Open hole
    - Pre-perforated liner
    - Partially pre-perforated liner + inflatable packers*
    - Cemented liner then perforating
  - Configuration selection:
    - Function of:
      - Initial conditions
      - Parameters evolution

Partially pre-perforated liner + inflatable packers



Problems specific to the payzone-borehole connection (cont.)

- **Liner running in:**
  - Enough but not too much centralizers
- **Liner cementing (if necessary):**
  - Usual precautions

  and:
  - Cleaning of the horizontal part
  - Enough centralizers
  - Prevention of the water migration from the slurry
- **Perforating:**
  - High cost
  - Methods: cf logging in horizontal hole
  - If TCP are used:
    - Guns have to be pulled out after fire
    - Mind the curve radius
  - Don't get stuck

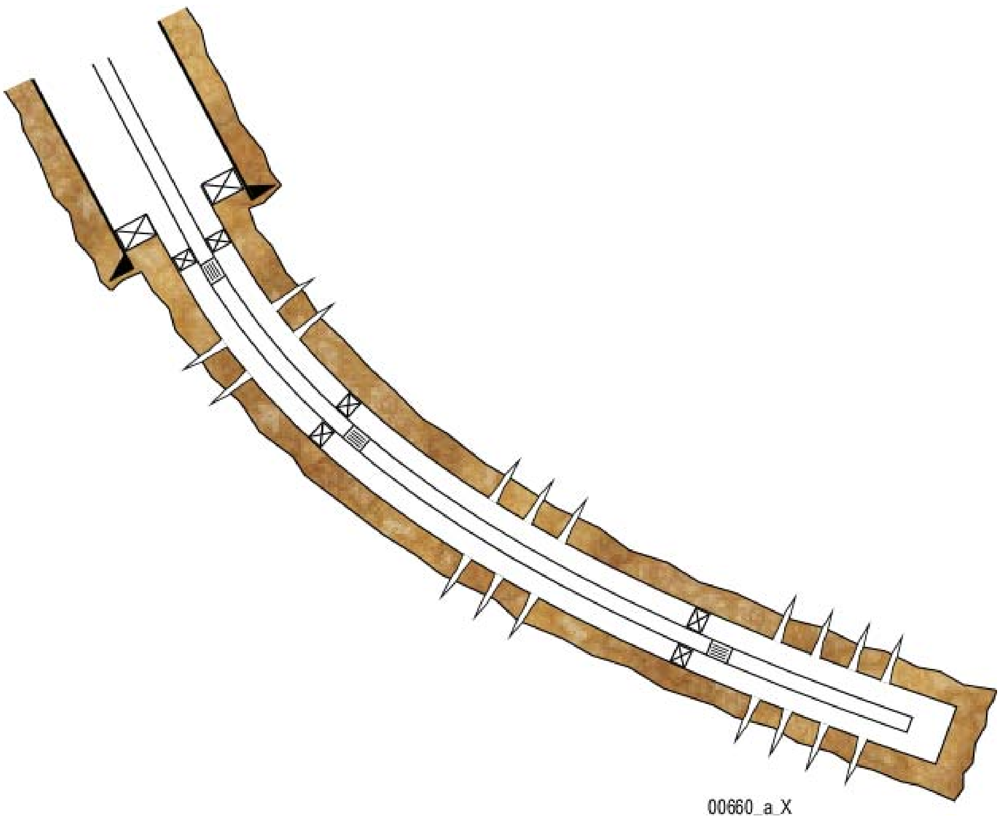
Problems specific to the payzone-borehole connection (cont.)

- **Sand control:**
  - Higher critical flowrate
  - Screens alone

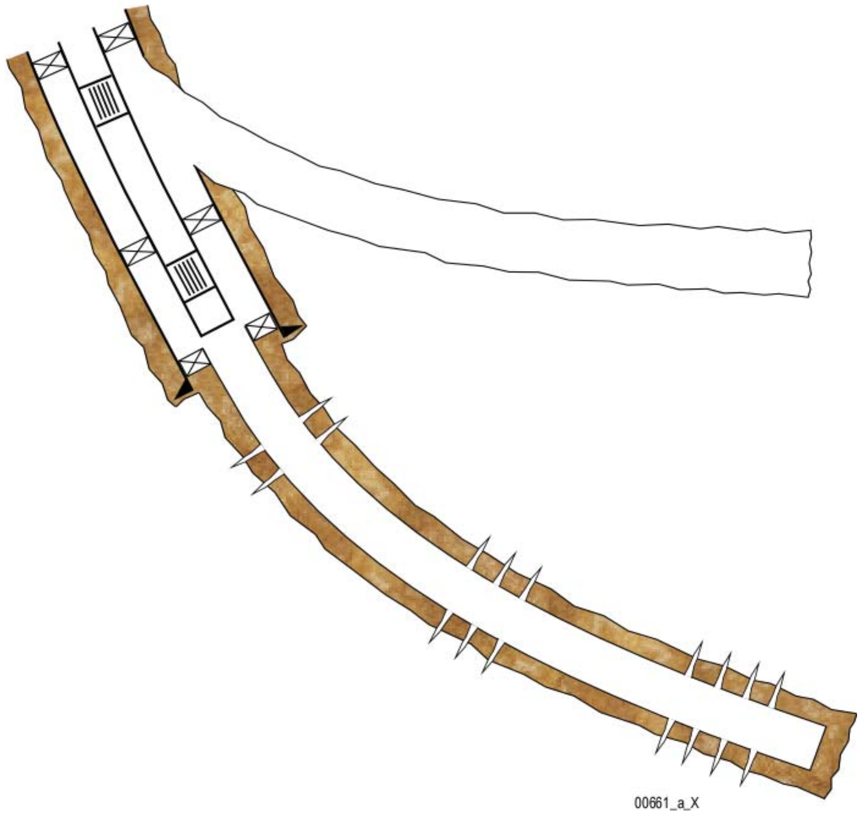
  or

  - Gravel packing (with specific screens or implementation techniques)
  - Consolidation not really applicable
- **Stimulation:**
  - Be careful to selectivity problems
- **Production string(s) configuration:**
  - Usually, single tubing string completion* (without or with zones selection) Possibly, multiple tubing strings completion*

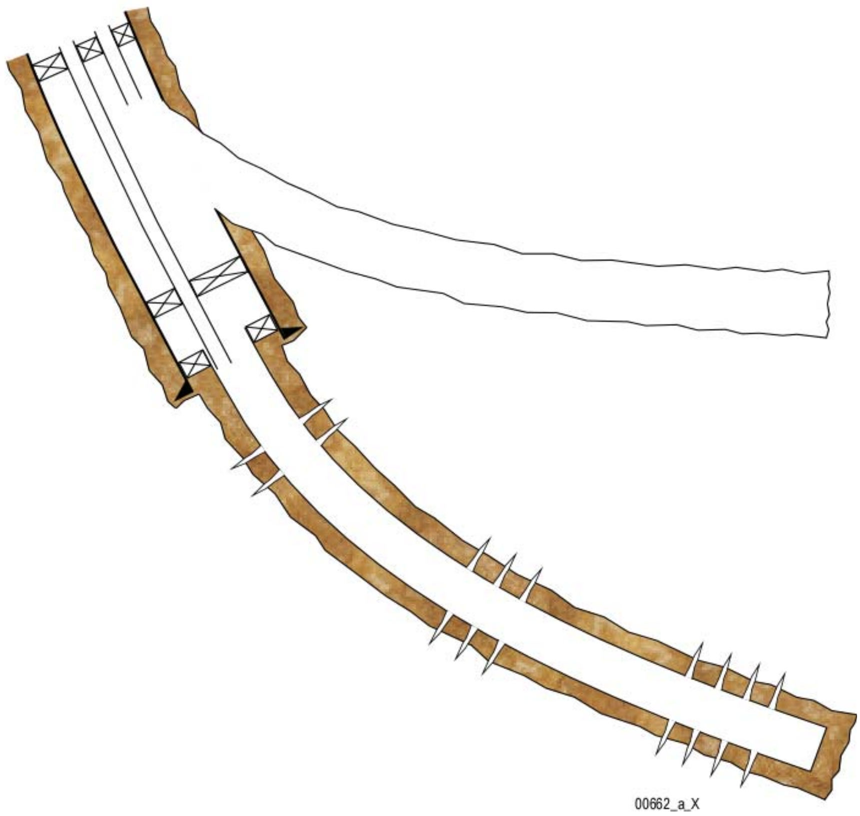
Selective completion in an horizontal monodrain well



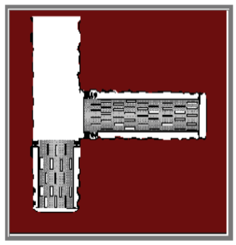
Selective completion in a multidrains well



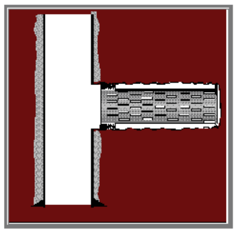
Dual tubing string completion in a multidrains well



- "A multi-lateral well is one in which there is more than one horizontal or near horizontal lateral well drilled from a single main bore and connected back to that main bore."*TAML 1997*
  - Level 1:
    - Open / unsupported junction
      (Barefoot mother-bore & lateral bore
      or with slotted liner in either bore)

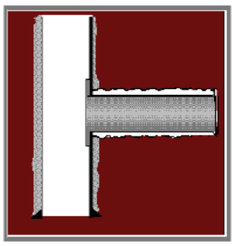


  - Level 2:
    - Mother bore cased and cemented
    - Lateral bore open
      (Lateral bore either barefoot
      or with slotted liner in openhole)

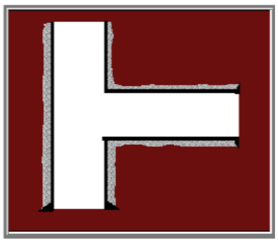


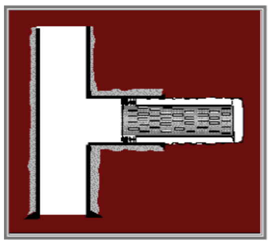
(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

- Level 3:
  - Mother bore cased and cemented
  - Lateral bore cased but not cemented
    (Lateral liner anchored to mother-bore with
    a liner hanger but not cemented)



- Level 4:
  - Mother bore cased and cemented
  - Lateral bore cased and cemented
    (Both bore <u>cemented at the junction</u>
    but no pressure integrity: cement not
    considered as a sealing mechanism)

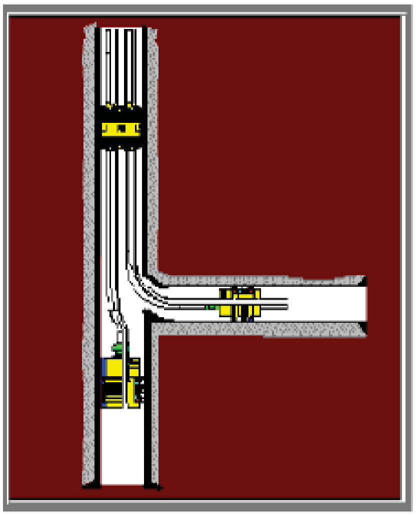




(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Multi lateral well: TAML(*) junction classification (cont.)

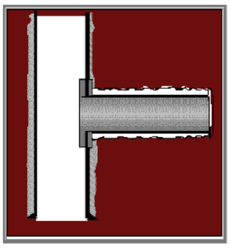
- Level 5:
  - Pressure integrity at the junction achieved with the completion
    (Cement not acceptable as not considered as a sealing mechanism)



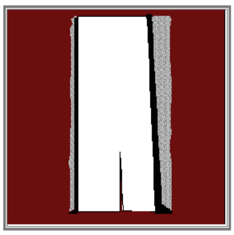
(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Multi lateral well: TAML(*) junction classification (cont.)

- Level 6:
  - Integral junction : pressure integrity at the junction achieved with the casings
    (Cement not acceptable as not considered as a sealing mechanism)



- Level 6S:
  - Integral junction : downhole splitter with pressure integrity
    (Large main bore with two or more smaller lateral bores)



(*): TAML group (North Sea) : Technology Advanced Multi-Lateral group

Equipment of naturally flowing wells

Sommaire

- Main configurations of production string
- Production wellhead
- Tubing (Production string)
- Packers
- Downhole accessories
- Subsurface safety valves
- Synthesis: example of equipment for a naturally flowing well
- Running procedure
- Intelligent completion

Main configurations of production string

Main parameters for completion design

- **Main parameters for completion design:**
  - Type of well: exploration, confirmation (or appraisal or delineation) or development
  - Well purpose: production, injection or observation
  - Naturally flowing well or artificial lift
  - Interface between fluids
  - Number of zones to be produced: (all together), separately
  - Anticipated measurement, maintenance or workover operations
- **To choose the best suited configuration:**
  - Greatest possible flow rate
  - At the lowest cost
  - $\Rightarrow$ Compromise

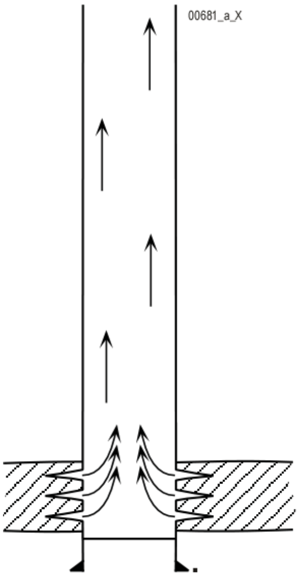
Main parameters for completion design (cont.)

- **Compromise taking into account:**
  - Costs:
    - Capital expenditure (CAPEX)
    - Operating expenditure (OPEX)
  - Relativity
  - Anticipation
  - and also:
  - Flowrate per well*
  - Risk:
    - In relation with the flowrate
    - In relation with safety
  - Cultural factor

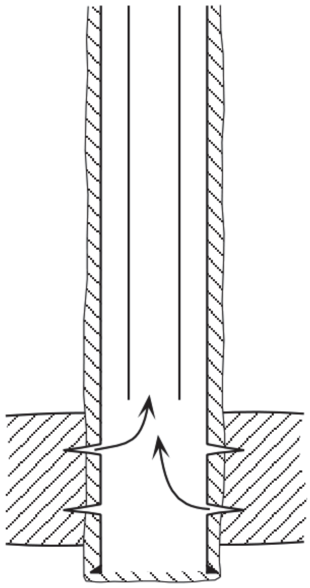
Functions to be carried out and corresponding pieces of equipment

FUNCTIONS TO BE CARRIED OUT	PIECES OF EQUIPMENT				
	Production wellhead	Tubing	Packer + annular fluid	Downhole accessories	SSSV
Safety					
among which : • **casing protection**					
Flowrate : • **adjustment** • **optimization**					
Operations on the well					

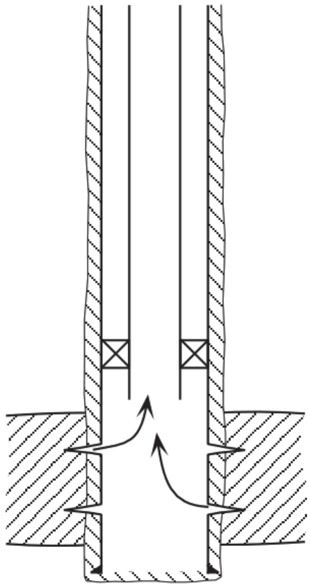
Single-zone completion



Tubingless completion

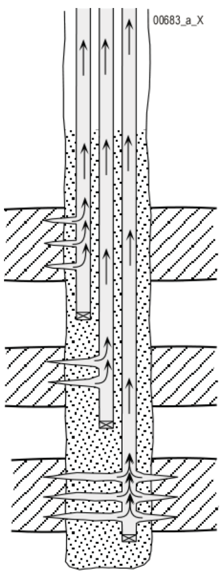


With tubing alone (no production packer)

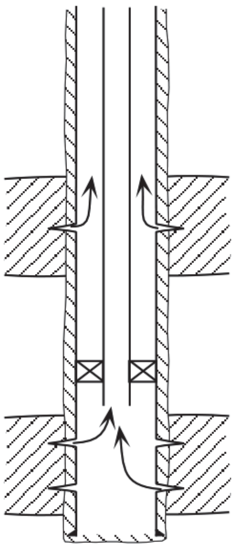


With tubing & production packer

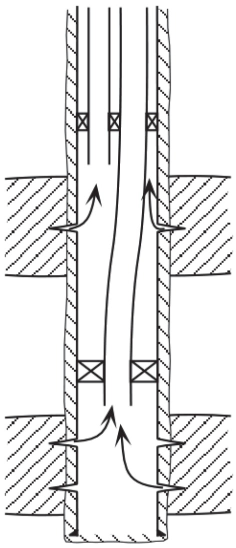
Multi-zones completion



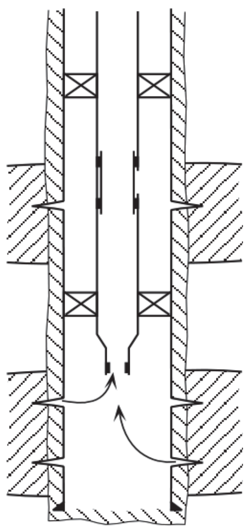
Tubingless completion



Tubing-annulus completion



Parallel dual tubing string completion



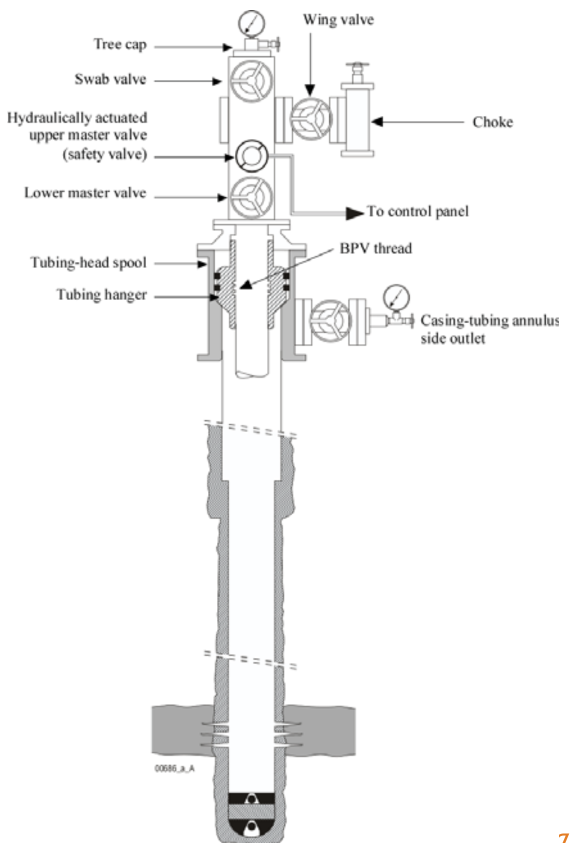
Alternate selective completion

Production wellhead

Summary

Production wellhead

- General configuration of a wellhead
- Tubing-head spool &
  Tubing hanger
- Christmas tree (Xmas tree)

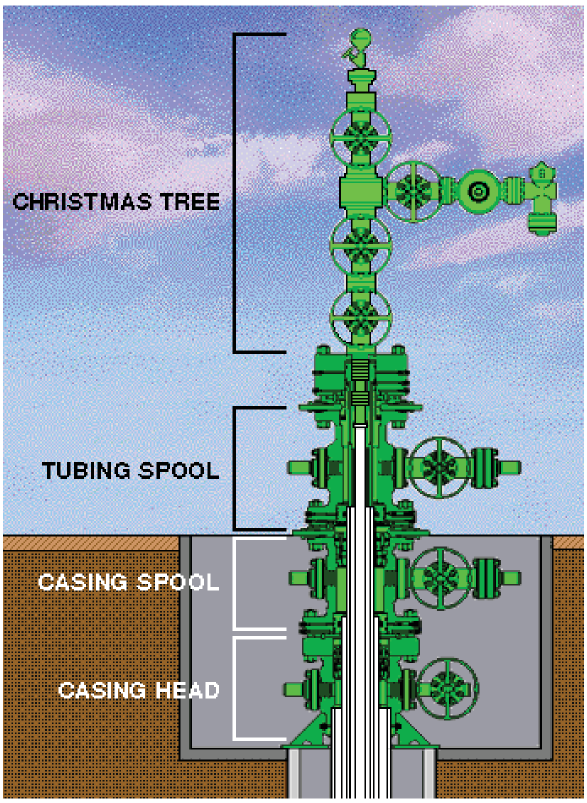


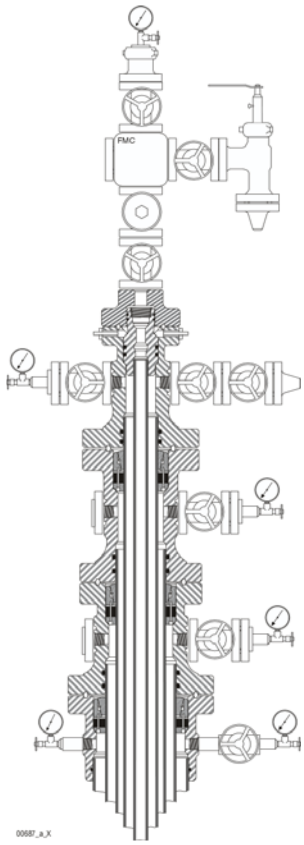
General configuration of a wellhead

PRODUCTION
- X-MAS TREE
- TUBING HEAD

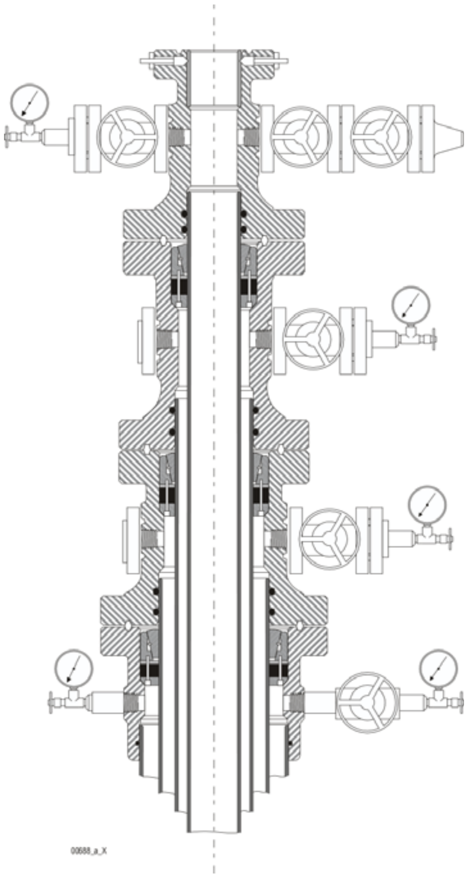
DRILLING
- CASING HEAD

General configuration of a wellhead (cont.)

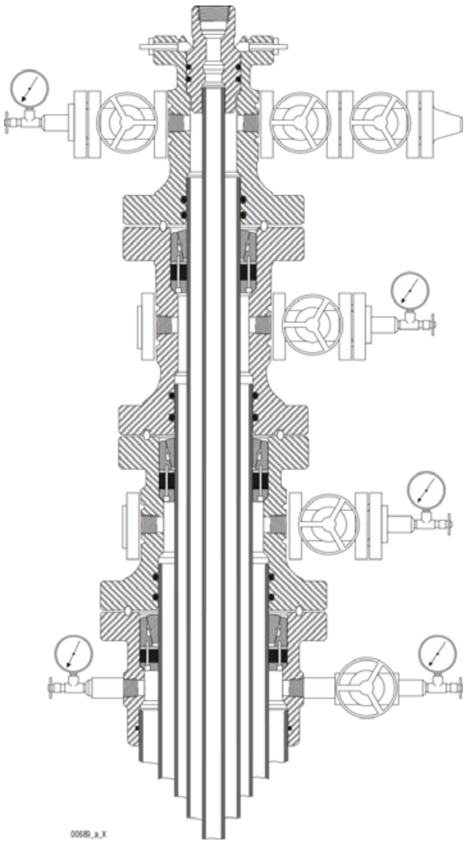




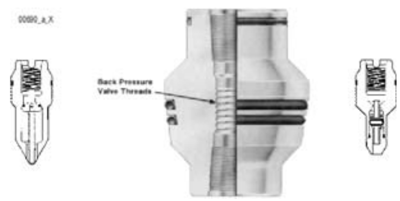
Casing-head & tubing-head spools

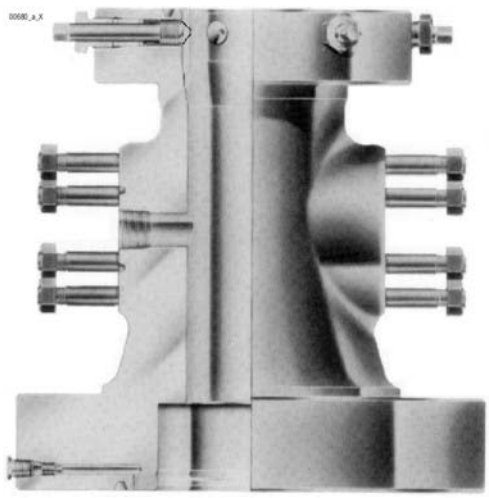


Casing-head & tubing-head spools (cont.)

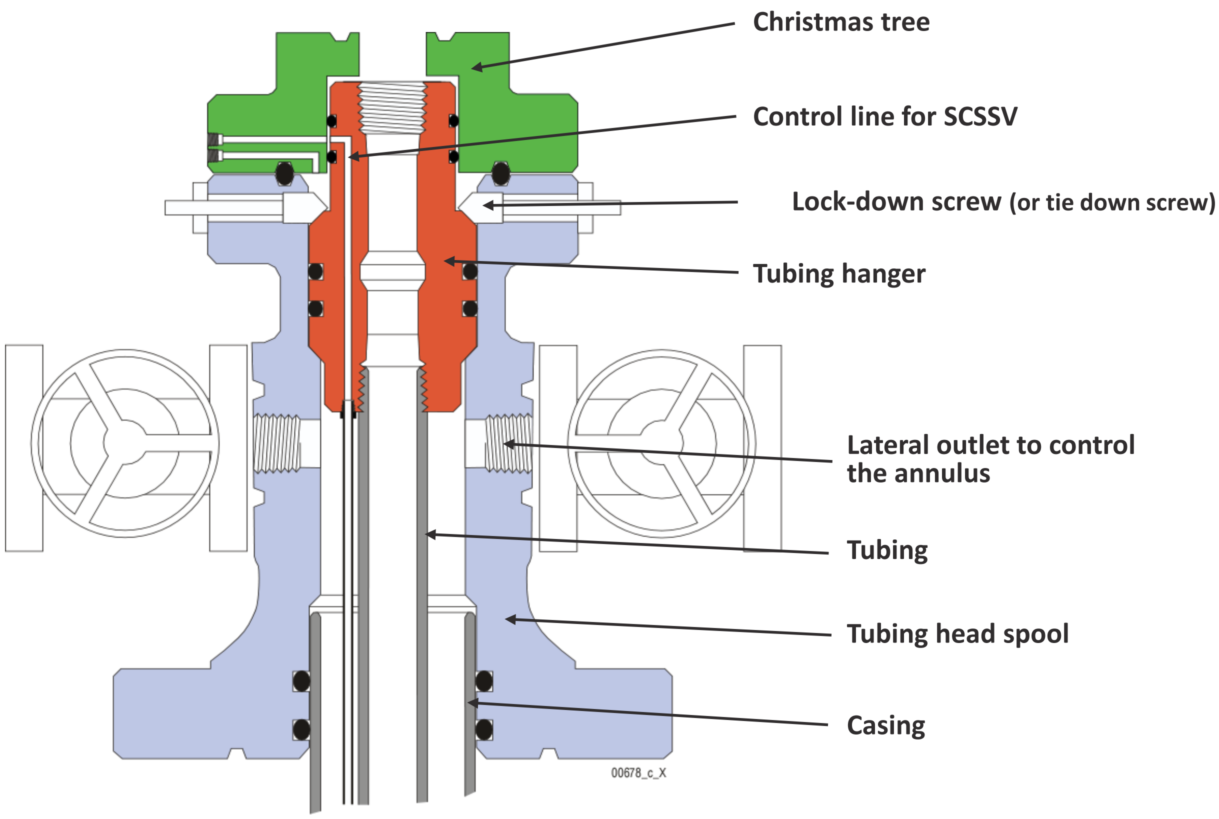


Tubing-head spool & tubing hanger

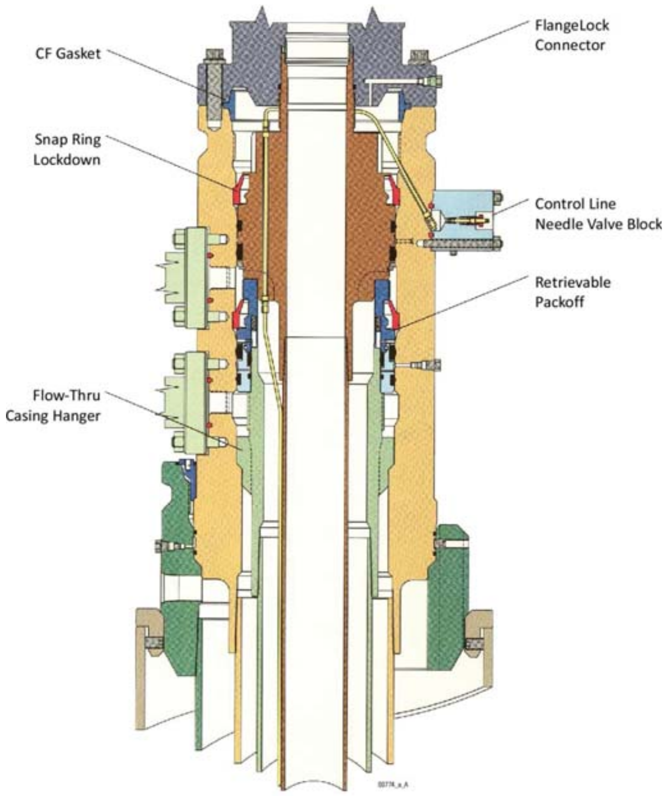




Tubing head spool assembly: Details

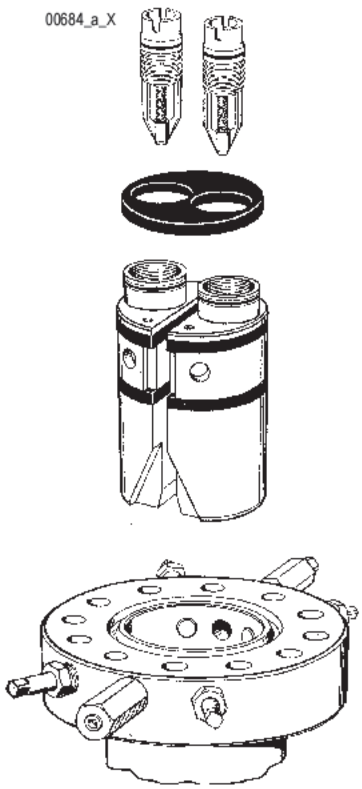


Compact head

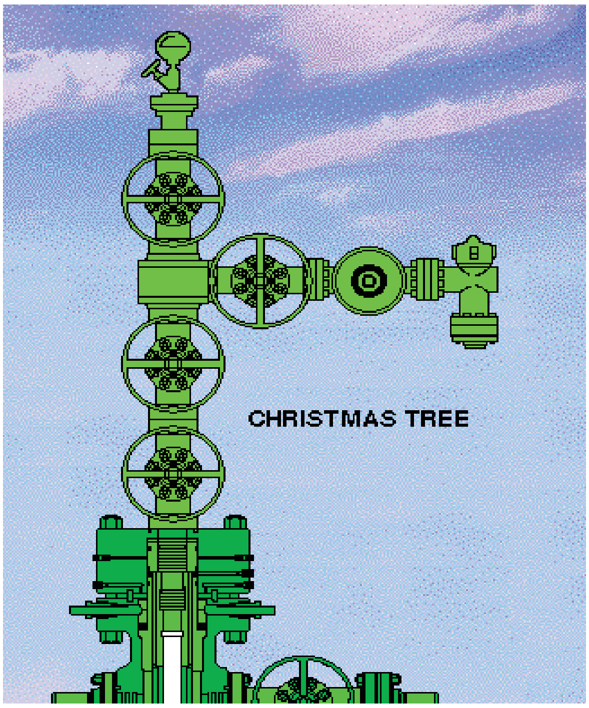


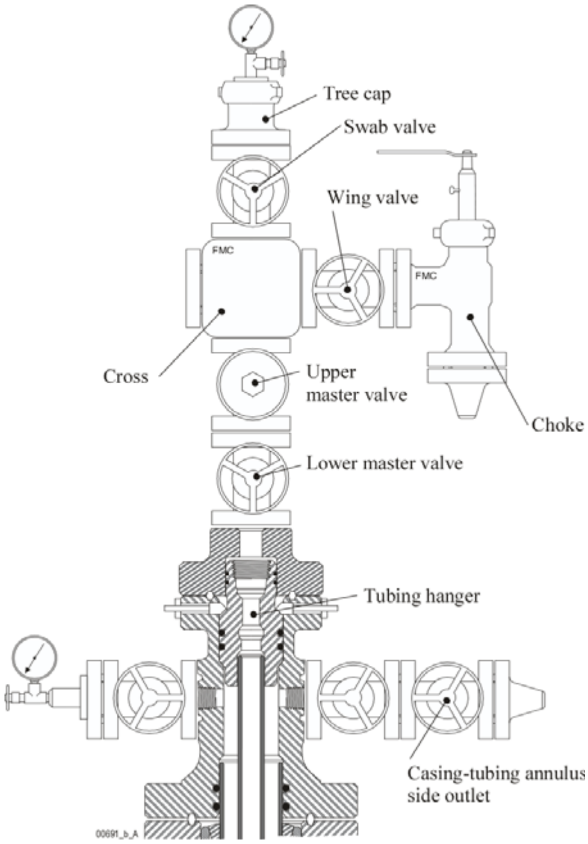
SSMC Wellhead

Tubing hanger for dual completion (segmented hanger)

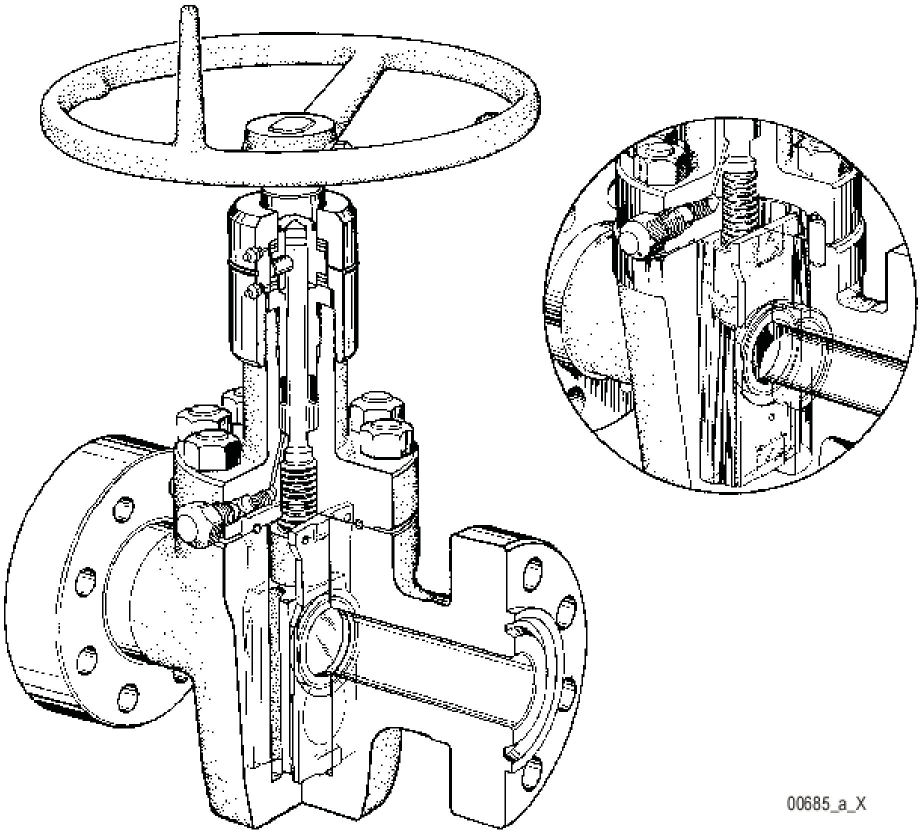


Production wellhead: general configuration

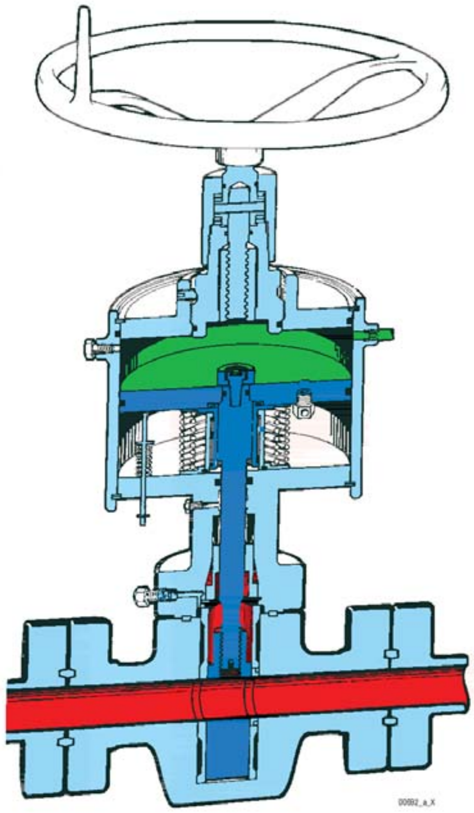




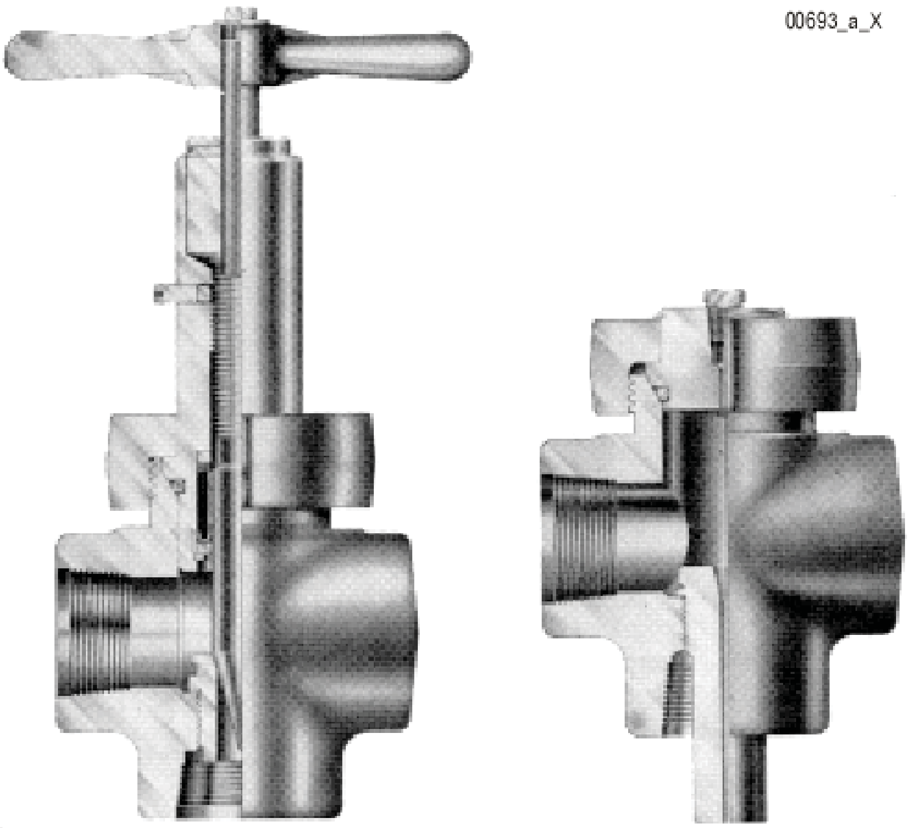
Gate valve



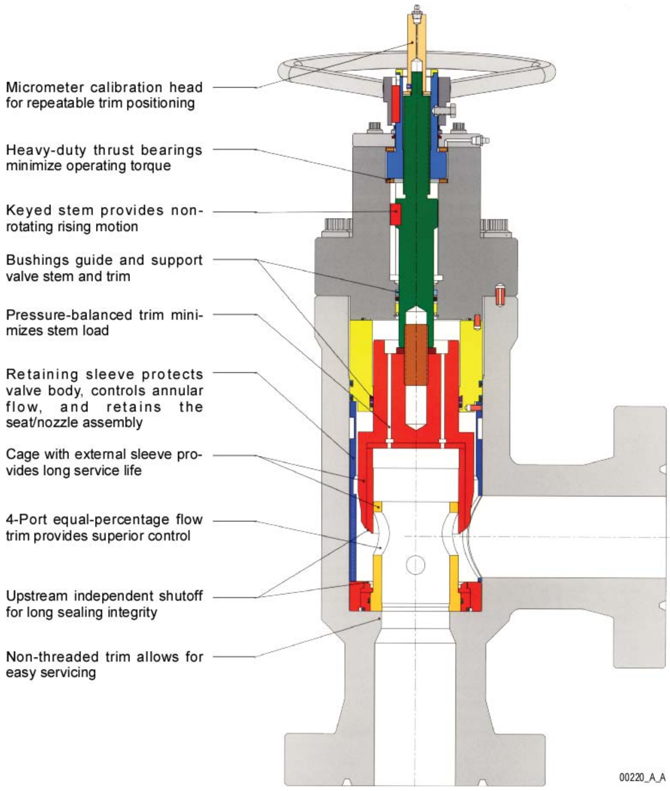
Surface safety valve

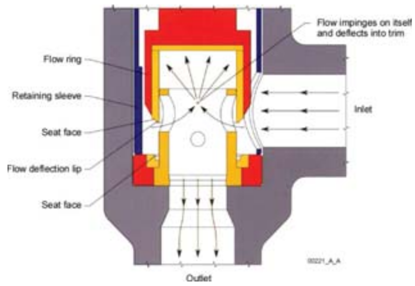


Choke assembly

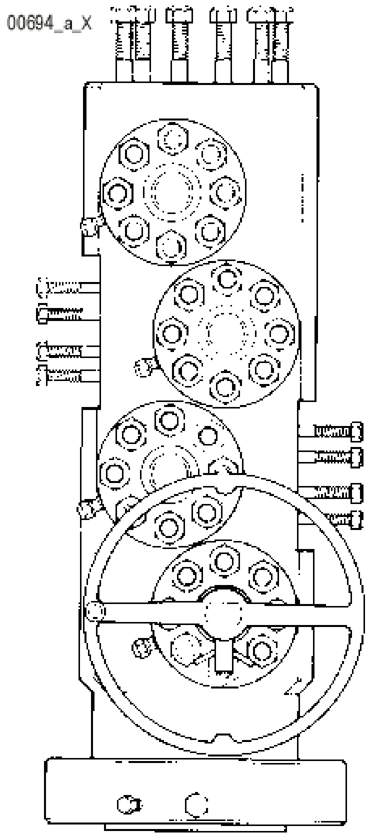


Cage choke valve

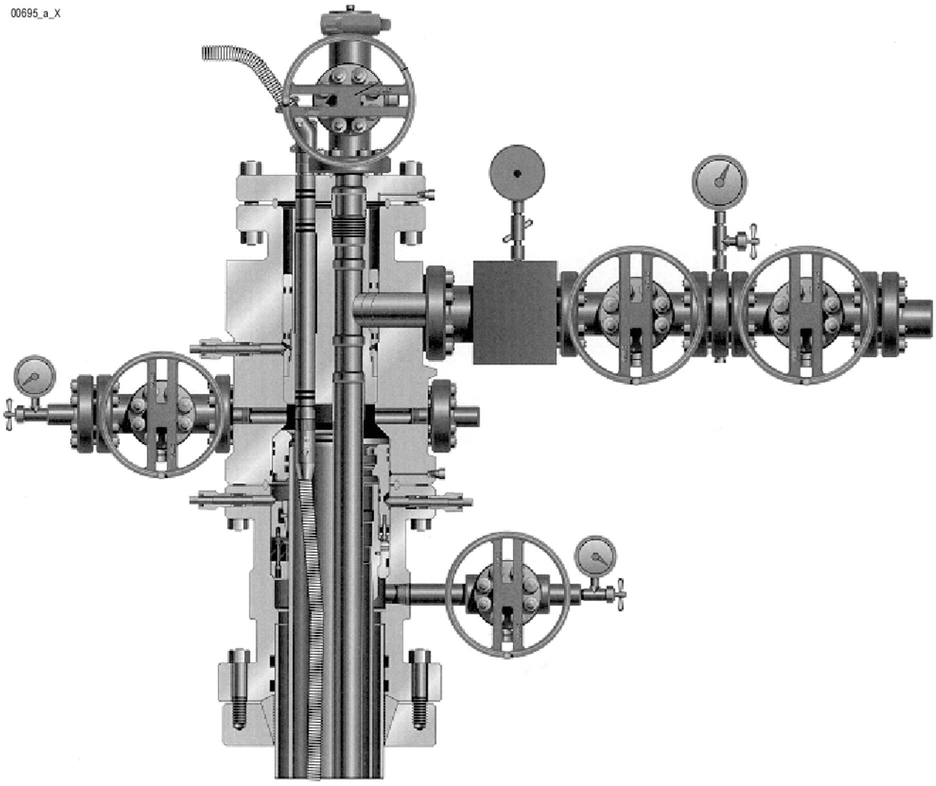




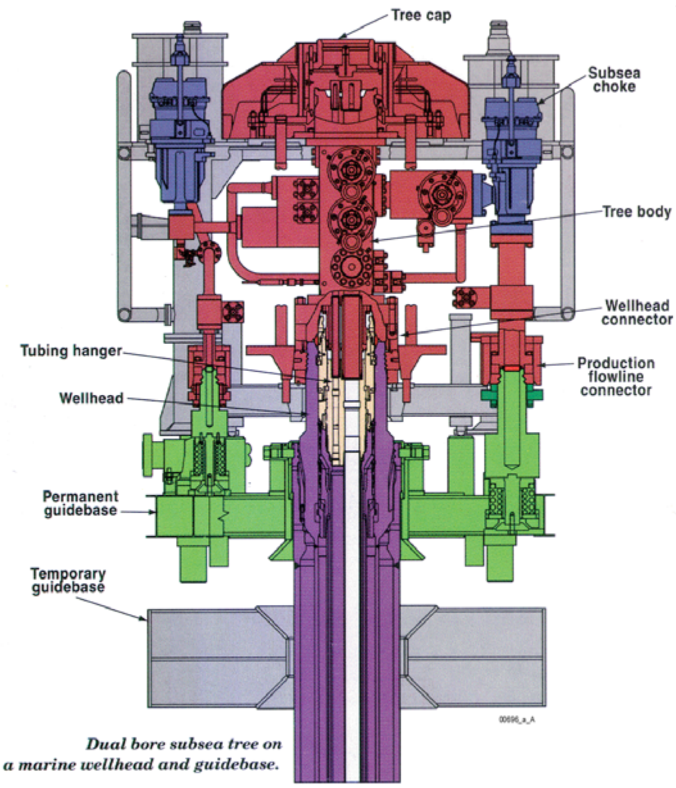
Solid block Christmas tree



Specific production wellhead: Horizontal tree for ESP completion (surface wellhead) (ESP: electrical submerged pump)

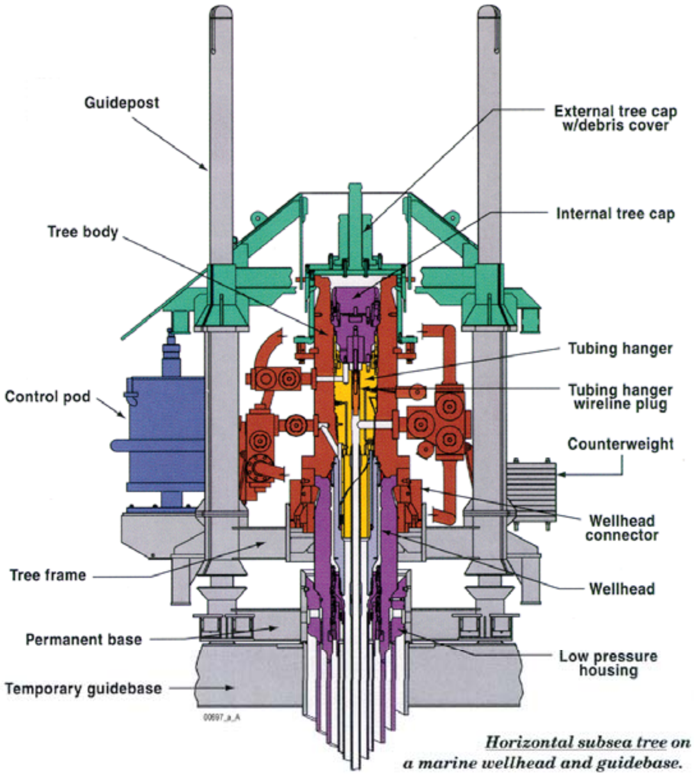


Specific production wellhead: Subsea production wellhead



Dual bore subsea tree on a marine wellhead and guidebase.

Specific production wellhead: Horizontal tree for ESP completion (subsea wellhead) (ESP: electrical submerged pump)



Horizontal subsea tree on a marine wellhead and guidebase.

Christmas tree selection

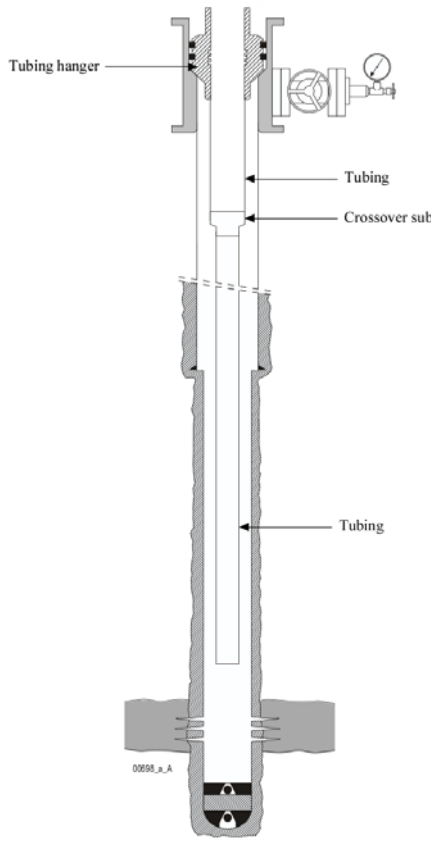
- **Working pressure:**
  - Maximum pressure (expressed in psi) at which the Xmas-tree can be used
  - Some value (API specification): 2000 – 3000 – 5000 – 10,000 – 15,000
  - Has to be equal or greater than the maximum expected pressure:
    - If gas or gassy oil: $WP \geq PR - PHgas + BHM$ (Bull Heading Margin)
      - (common value for BHM: 500 psi or 35 bar)
    - If hydraulically set packer: check also with the pressure required to set the packer
- **Nominal diameter:**
  - Minimum inside diameter through it
  - Has to be equal or greater than the tubing ID
- **And metallurgy, packing material**

Tubing

(Production string)

Tubing… or production string

- Tubing characteristics
- Choosing the tubing



Tubing characteristics

- **Nominal diameter & Geometrical characteristics:**
  - Nominal diameter*
  - Inside diameter and thickness
  - Drift diameter*
  - Maximum outside diameter
  - Pipe length:
    - Range 1: 20 - 24 ft (6.10 - 7.32 m)
    - Range 2: 28 - 32 ft (8.53 - 9.75 m)
    - Pup joints:2 - 4 - 6 – 8 - 10 - 12 ft (0.61 - 1.22 - 1.83 - 2.44 - 3.05 - 3.66 m)
- **Connections & Thread:**
  - API connections & Premium joints*
- **Nominal weight***

Nominal diameter & drift diameter

- Nominal diameter:

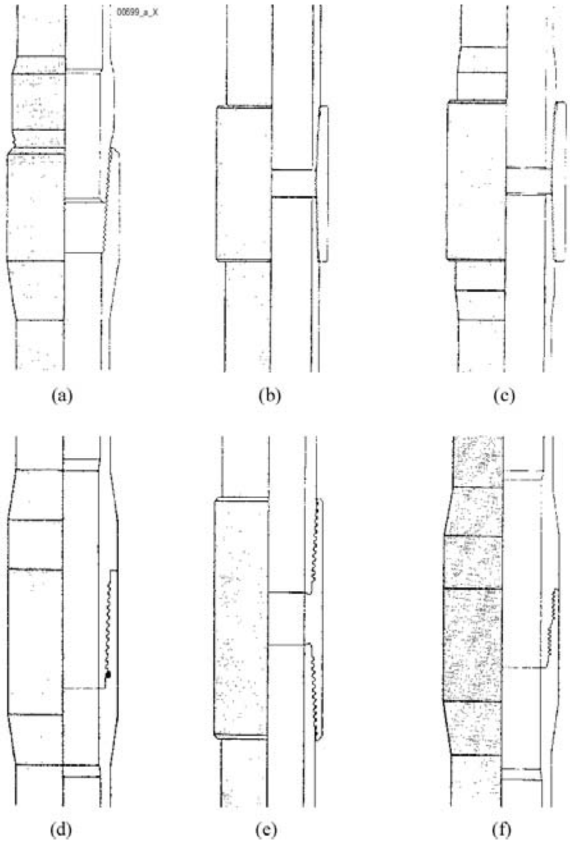
inches	*1.050*	*1.315*	*1.660*	*1.900*	*2.063*	*2 3/8*	*2 7/8*	*3 1/2*	*4*	*4 1/2*
mm	26.7	33.4	42.2	48.3	52.4	60.3	73.0	88.9	101.6	114.3

Note: 2 3/8 = 2.375
2 7/8 = 2.875

- Drift diameter:

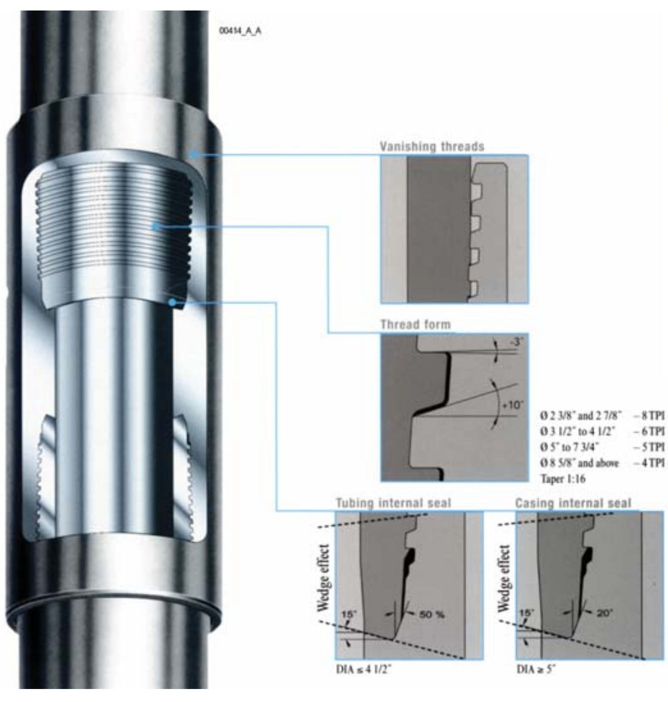
	Diameter	Mandrel length		Mandrel diameter	
		in	mm	*in*	mm
Tubing	2 7/8 or less	*42*	1067	*ID – 3/32*	ID – 2.38
	3 1/2 or more	*42*	1067	*ID – 1/8*	ID – 3.18
Casing	8 5/8 or less	*6*	*152*	*ID – 1/8*	ID – *3.18*
	9 5/8 to 13 3/8	*12*	*305*	*ID – 5/32*	ID – *3.97*
	16 or more	*12*	*305*	*ID – 3/16*	ID – *4.76*

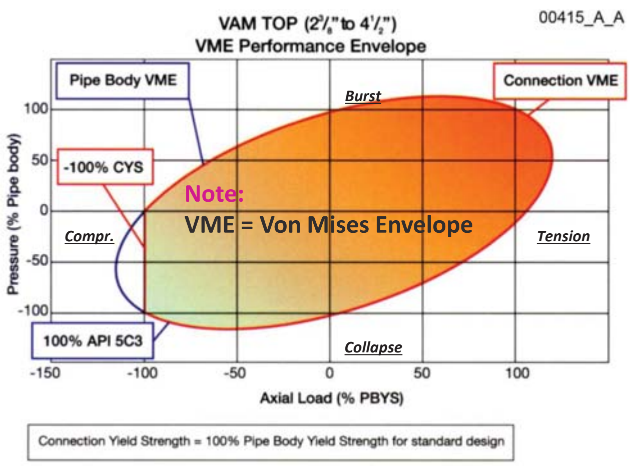
Examples of tubing connections

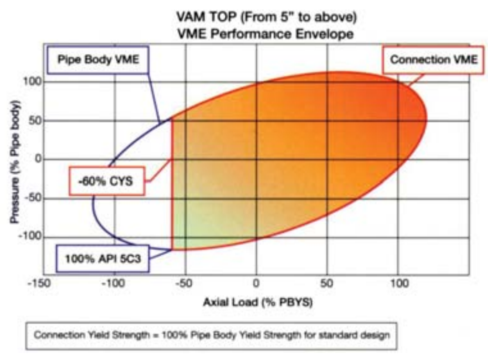


a. API integral joint
b. API non-upset
c. API external upset
d. Elastomer joint
e. VAM joint
f. CS Hydril joint

VAM TOP joint







Examples of nominal weights for a 3 1/2" tubing

Thickness mm *inch*	Nominal weight *(#)*	
	with API NU (or VAM) connection	with API EU connection
6.45 *0.254*	*9.20*	*9.30*
9.52 *0.375*	*12.70*	*12.95*

Tubing characteristics (cont.)

- **Grades of steel & metallurgical characteristics:**
  - API standard steel and grades for tubings: H40, J55, C75, L80, N80, C90, P105*
  - Improved grades of steel (proprietary grades)
  - Stainless, alloys and special pipe
- **Mechanical characteristics:**
  - Main characteristics:
    - Body yield strength
    - Burst or internal yield pressure
    - Collapse pressure
  - Deduced from:
    - Nominal diameter
    - Nominal weight
    - Grade
    - Connection

Grades and mechanical properties of tubing pipe

PROPERTIES	GRADE						
	H40	J55	C75[1]	L80[1]	N80	C90	P105
Color band identification[2]	1 black	1 green	1 blue	1 red + 1 brown	1 red	1 purple	1 white
Minimum yield stress (MPa) *(psi)*	276 *40 000*	379 *55 000*	517 *75 000*	552 *80 000*	552 *80 000*	620 *90 000*	724 *105 000*
Maximum yield stress (MPa) *(psi)*	552 *80 000*	552 *80 000*	620 *90 000*	655 *95 000*	758 *110 000*	724 *105 000*	930 *135 000*
Minimum tensile stress (MPa) *(psi)*	414 *60 000*	517 *75 000*	655 *95 000*	655 *95 000*	689 *100 000*	689 *100 000*	827 *120 000*

1. Special corrosion.
2. Special clearance couplings (smaller diameter) must have a black line at the centre of the colour band.

Choosing the tubing - Nominal diameter

- **Main parameters to consider:**
  - Flowrate / pressure losses*
  - Lifting capacity:
    - ⇒ V > Vmin
  - Erosion:
    - ⇒ V < Vmax
  - Operations in or through the tubing:
    - ⇒ tubing & downhole accessories drift diameter > tool OD
  - Casing size:
    - ⇒ tubing and accessoiries max. O.D. < casing drift Ø
- **Don't forget:**
  - The value of these parameters depends also of :
    - The nominal weight
    - The connection

Tubing diameters and potential flow rates

Nominal tubing diameter *(in)*	Nominal weight *(lb/ft)*	Inside diameter (mm)	Inside diameter *(in)*	Drift (mm)	Drift *(in)*	Oil flow rate (m^3/d)	Oil flow rate *(bbl/d)*	Gas flow rate (P = 15 MPa ≅ *2200 psi*) ($10^3 sm^3$/d)	Gas flow rate (P = 15 MPa ≅ *2200 psi*) *(10^6 scuft/d)*
2 3/8	*4.6*	50.7	*1.945*	48.3	*1.901*	150	*900*	150	*5*
2 7/8	*6.4*	62	*2.441*	59.6	*2.347*	275	*1700*	275	*10*
3 1/2	*9.2*	76	*2.992*	72.8	*2.867*	450	*2800*	450	*16*
4	*11.0*	88.3	*3.476*	85.1	*3.351*	700	*4400*	700	*25*
4 1/2	*12.6*	100.5	*3.958*	97.4	*3.833*	1000	*6300*	1000	*35*
5 1/2	*17*	124.3	*4.892*	121.1	*4.767*	1700	*11,000*	1700	*60*
7	*29*	157.1	*6.184*	153.9	*6.059*	3000	*19,000*	3000	*105*
9 5/8	*47*	220.5	*8.681*	216.5	*8.525*	7000	*44,000*	6000	*210*

CRITERIA a) OIL : $\Delta P_{friction} \leq$ 0.25 MPa/1000 m *(10 psi / 1000 ft)* & velocity ≤ 2 m / s *(6.5 ft / s)*
b) GAS : $\Delta P_{friction} \leq$ 1 MPa/1000 m *(40 psi / 1000 ft)* & velocity ≤ 10 m / s *(33 ft /s)*

Grade & Nominal weight

- **Main parameters to consider:**
  - Tensile strength:
    - Depth
    - Tubing pressure test when running in
    - Additional stress due to tubing breathing
    - Workover
  - Burst and collapse pressure
  - Thickness:
    - Erosion
    - Corrosion

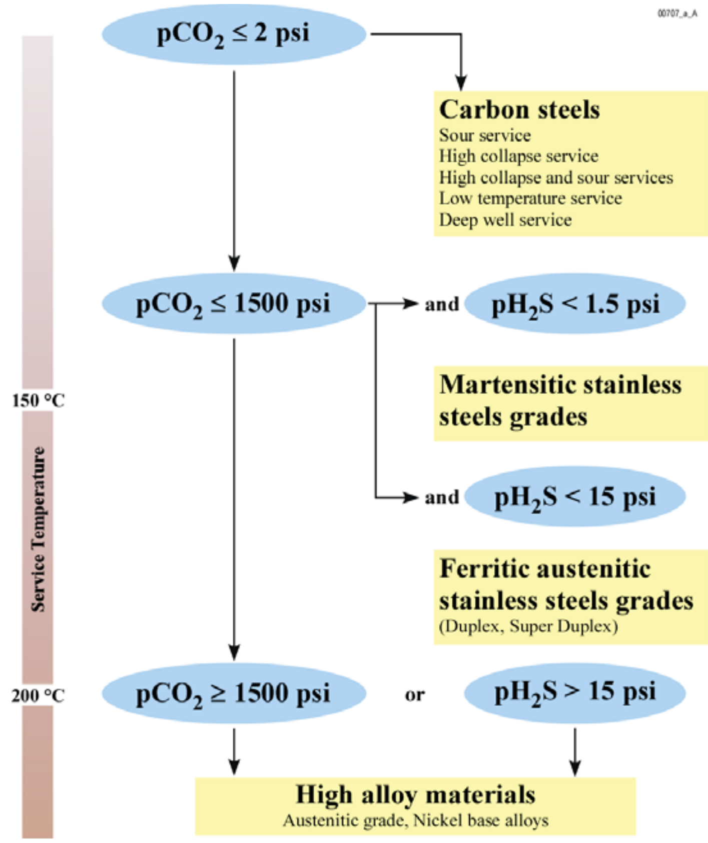
Grade & Nominal weight (cont.)

- **Other parameters relative to the connection between the tubing and the packer:**
  - If the tubing is fixed in the packer:
    - Tension or compression
  - If the tubing is free to slide in the packer:
    - Stretching or shortening movements
  - Buckling, if any
  - Differential of pressure on the packer

Connection & Metallurgy

- **Main parameters to consider:**
  - Oil and gas
  - Pressure, Temperature
  - Corrosion:
    - CO_2, H_2S*
    - Connate water

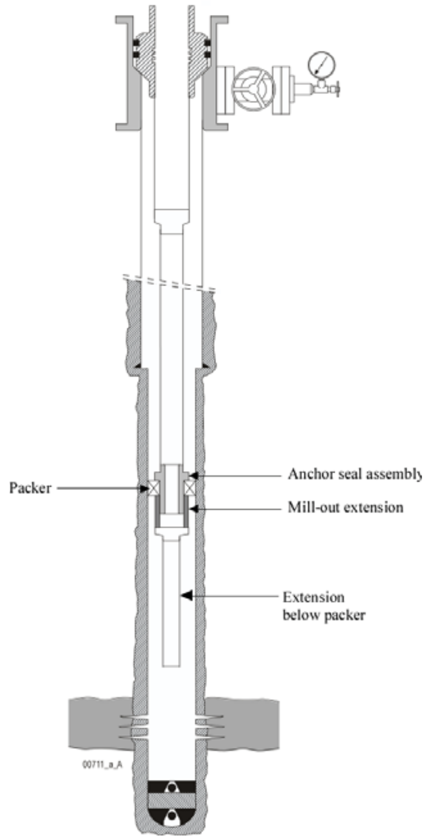
Material selection guideline



Packers

Packers

- Packer fluids (or annular fluids)
- Main packer types
- Permanent production packers
- Retrievable packers
- Choosing the packer



Packer fluids (or annular fluids)

- **Functions and requirements:**
  - To protect the casing $\Rightarrow$ "non corrosive" fluids
  - No settling $\Rightarrow$ free solid fluids
  - To decrease efforts on packer, casing, tubing
  - Help to well control
- **Main fluids (depending on the required specific gravity):**
  - Brine
  - Water
  - Diesel oil
  - Oil
- **Protection against corrosion:**
  - High PH (> 9.5)
  - Oxygen scavenger
  - Film-forming and antibacterial products (problem of compatibility between products)

Main packer types

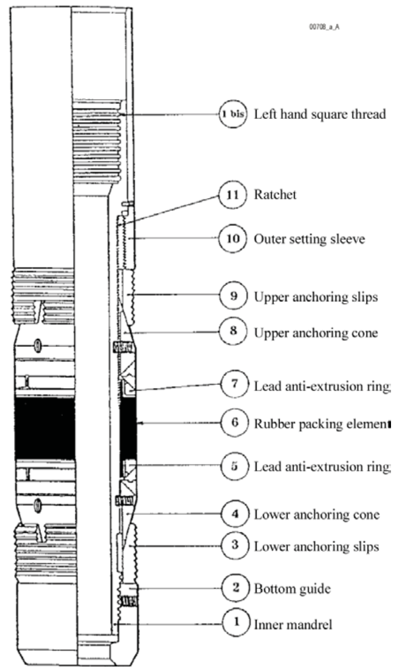
- **Main characteristics:**
  - Seal
  - Anchoring device
  - Setting mechanism
  - Type of tubing-packer connection
  - Mean of retrieval
- **Classification (based on the mean of retrieval):**
  - Permanent packers
  - Retrievable

Example of permanent production packers: 415 D packer

- **Description of the 415 D packer***
- **Setting the 415 D packer:**
  - On pipe string*
  - On electric cable*
- **Tubing to 415 D packer connection***
- **Drilling out the 415 D packer***
- **For more information: example of classification***

Permanent or drillable production packer:

415 D Packer



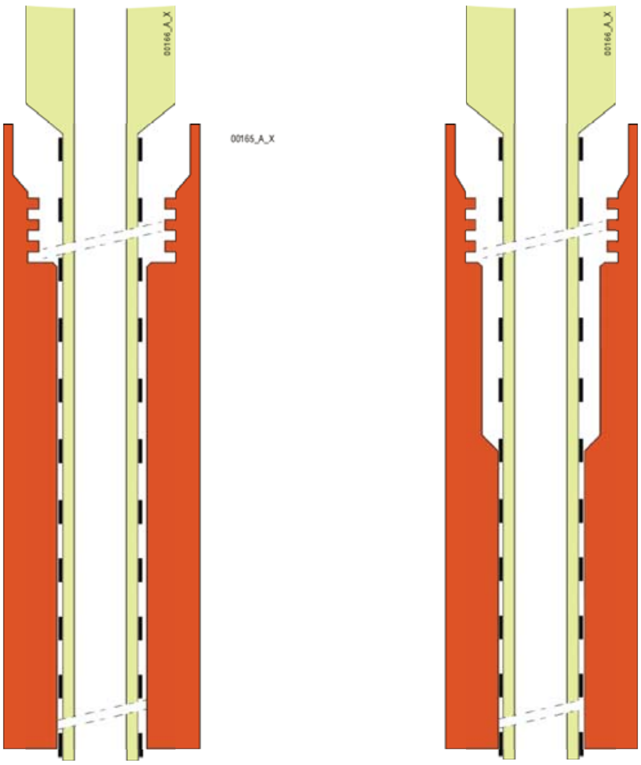
Tubing to permanent packer connection

Locator seal assembly

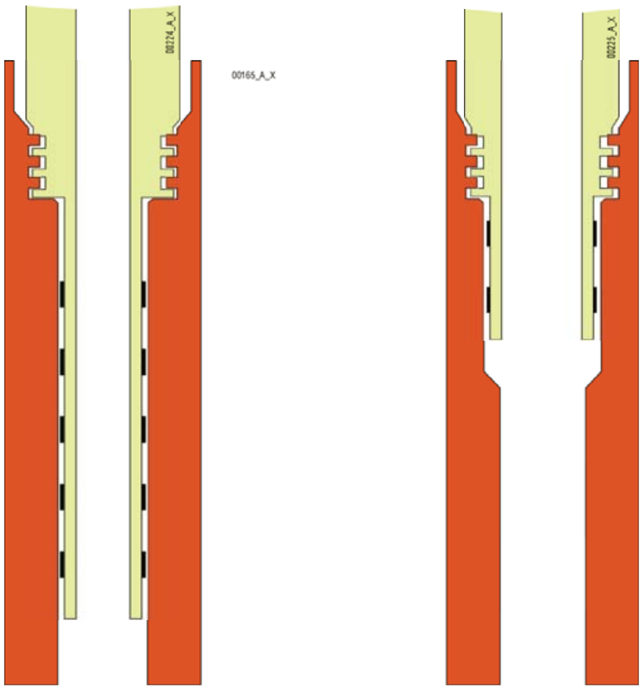
Anchor seal assembly

Washover mill for a permanent packer

Baker permanent packers: Classification



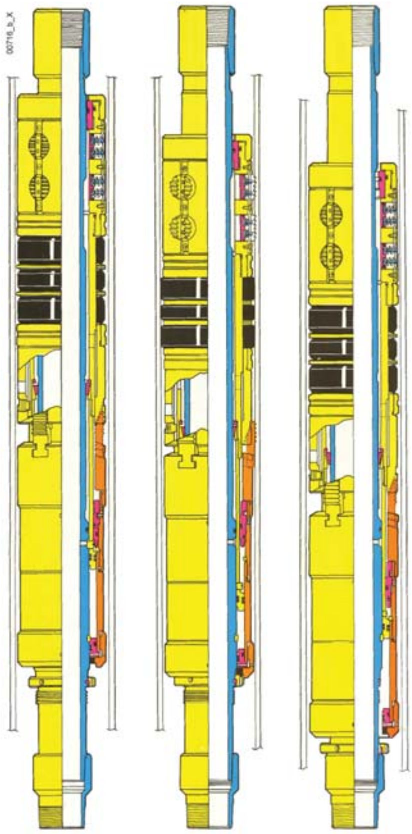
Baker permanent packers: Classification (cont.)

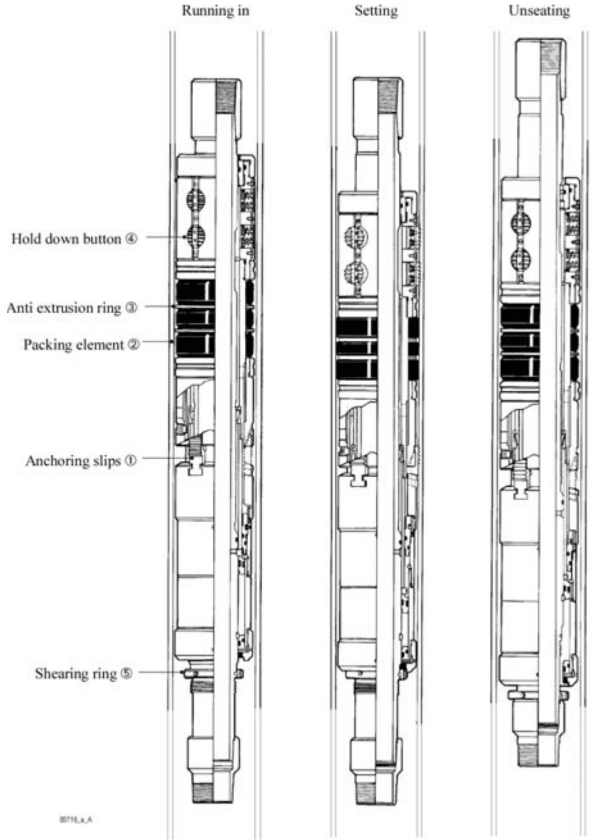


Retrievable packers

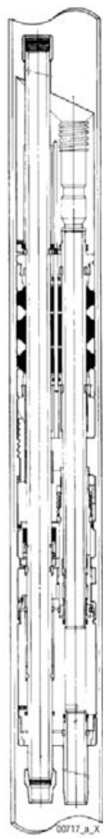
- Hydraulically set*
- Mechanically set*

Retrievable hydraulic packer





Dual retrievable packer



Retrievable mechanical packer

Tension setting

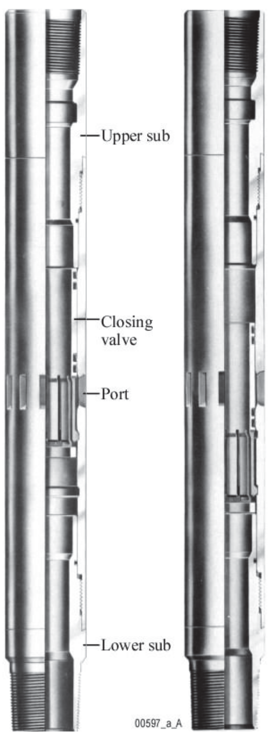
Compression setting

Downhole accessories

Circulating devices

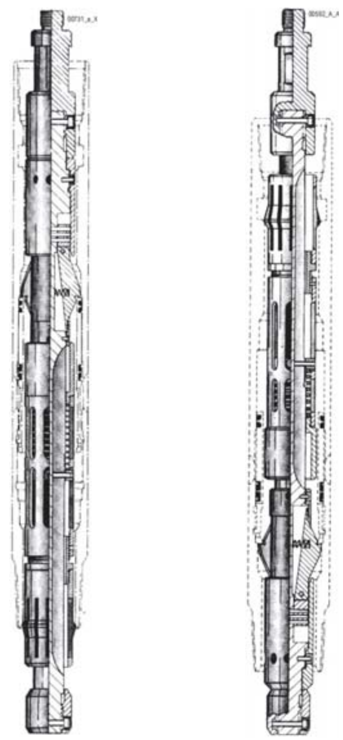
- Sliding sleeve (SS) or Sliding side door (SSD)*
- Side pocket mandrel (SPM)*
- Ported landing nipple*

Sliding sleeve & Shifting tool



Open closed

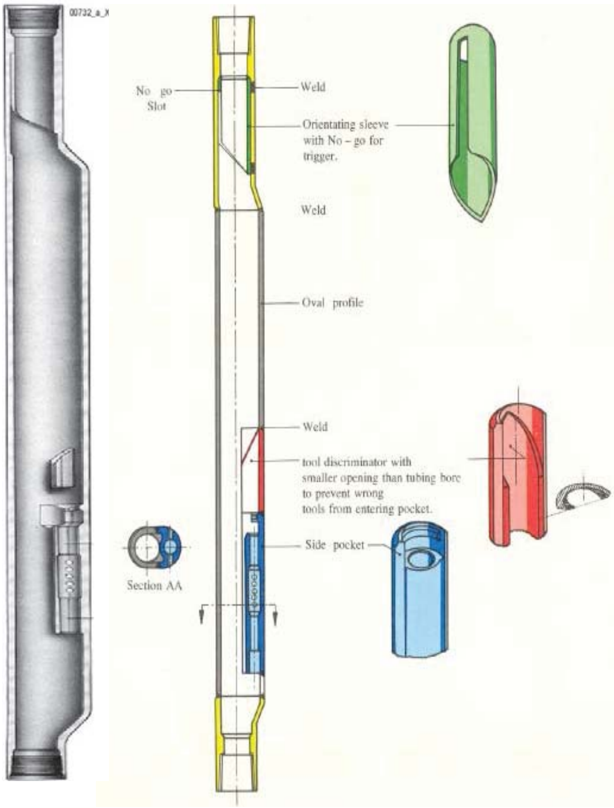
Sliding sleeve

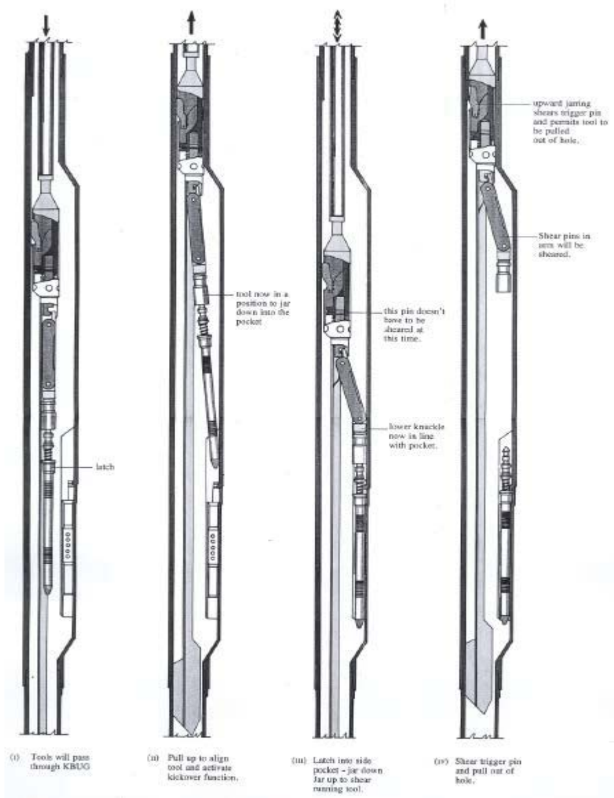


Closing Opening

Shifting tool

Side pocket mandrel & Kickover tools





Ported landing nipple

Landing nipples & corresponding accessories

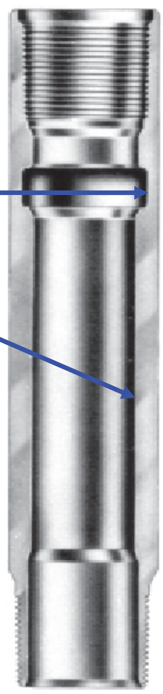
- **Landing nipple & tool components***
- **Landing nipple classification*:**
  - Full bore:
    - Simple
    - Selective
    - Top no-go
  - Bottom No-Go
- **Top or bottom no-go landing nipple & accessories (blanking plug & equalising check valve): example***

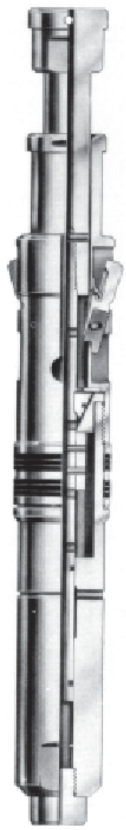
Landing nipple (LN) & tool components: example

Constituant parts:
- **Looking groove**
- **Seal bore**
- **…**

$\varnothing_N = \varnothing_{seal\ bore}$

$\Rightarrow$ Classification:
- **Full bore LN:**
  $\varnothing_{mini} = \varnothing_{seal\ bore}$
- **Bottom no go LN:**
  $\varnothing_{mini} < \varnothing_{seal\ bore}$





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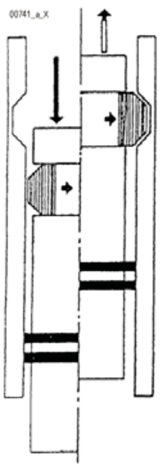
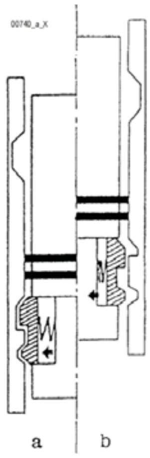
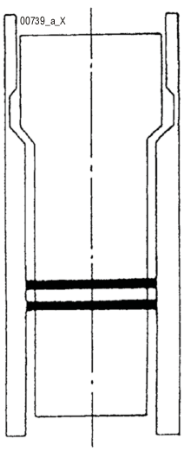
Landing nipple classification

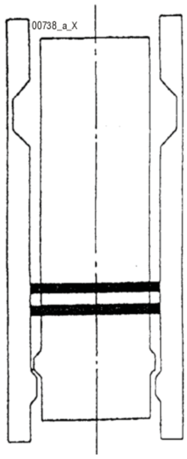


*



*





*

FULL BORE

simple | selective | top no-go

BOTTOM NO-GO

Top or bottom NO-GO landing nipple & accessories (blanking plug & equalising check valve): example

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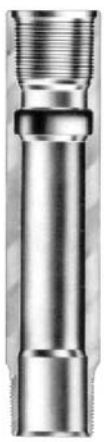
Model "FWG"


Nipple "F"


Model "FB-2"

Top NO-GO landing nipple & plugs

00759_a_X


Model "RB-2"


Nipple "R"


Model "RZG"

Bottom NO-GO landing nipple & plugs

Example of "landing nipple & tubing" compatibility

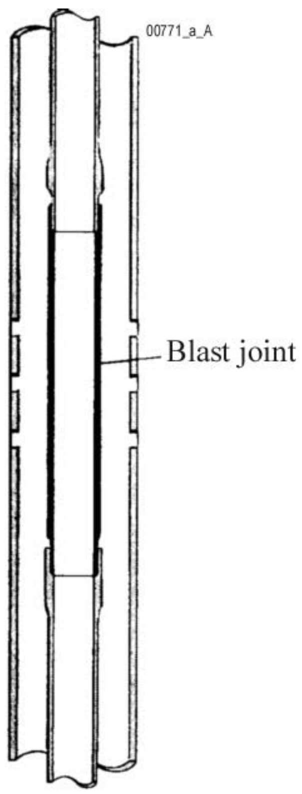
<table>
<tr><td rowspan="3">Landing nipple</td><td colspan="2">Nominal Ø</td><td>2.81 F</td><td>2.75 F</td><td>2.75 R</td><td>2.56 F</td><td>2.56 R</td></tr>
<tr><td>Seal bore Ø</td><td>in
mm</td><td>2.812
71.42</td><td>2.750
69.85</td><td>2.750
69.85</td><td>2.562
65.07</td><td>2.562
65.07</td></tr>
<tr><td>Bottom no-go Ø</td><td>in
mm</td><td></td><td></td><td>2.697
68.50</td><td></td><td>2.442
62.03</td></tr>
<tr><td colspan="2">FB-2 or RB-2 max. OD</td><td>in
mm</td><td>2.865
72.77</td><td>2.802
71.17</td><td>2.740
69.60</td><td>2.625
66.68</td><td>2.552
64.82</td></tr>
<tr><td colspan="3">Compatibility between landing nipples</td><td colspan="5">Yes</td></tr>
<tr><td rowspan="4">Compatibility with tubing 3 1/2 (88.90 mm)</td><td>7.70 #</td><td>ID 3.068 77.93
Drift 2.943 74.75</td><td colspan="5">Yes</td></tr>
<tr><td>9.20 #</td><td>ID 2.992 76.00
Drift 2.867 72.82</td><td colspan="5">Yes</td></tr>
<tr><td>10.20 #</td><td>ID 2.922 74.22
Drift 2.797 71.04</td><td>No</td><td>No because of the FB-2 max OD</td><td colspan="3">Yes</td></tr>
<tr><td>12.70 #</td><td>ID 2.750 69.85
Drift 2.625 66.68</td><td colspan="3">No</td><td>(Yes)</td><td>Yes</td></tr>
</table>

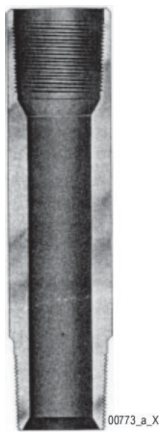
Other downhole accessories

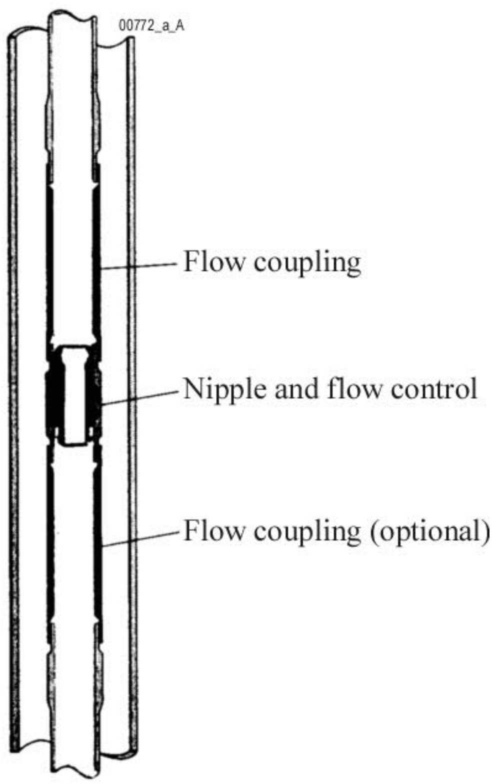
- Perforated tube
- Safety joint
- Slip joint
- Disconnecting joint*
- Blast joint & Flow coupling*
- Etc.

Tubing seal receptacle

Blast joint & Flow coupling







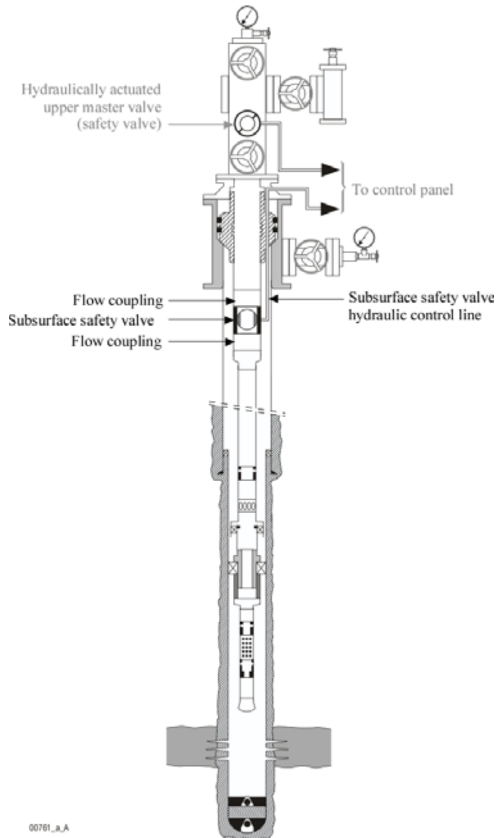
Blast joint

Flow coupling

Subsurface safety valves

Subsurface safety valves

- Subsurface Safety Valve (SSSV) terminology & technology
- SCSSV testing procedure



Subsurface safety valves: terminology & technology

- **Surface Safety Valves (SSV): for memory**
- **SubSurface Safety Valve (SSSV):**
  - SubSurface Controlled subsurface Safety Valves (SSCSV)*:
    - Pressure differential safety valves (or velocity safety valve)*
    - Pressure operated valves (or ambient safety valves)*
  - Surface Controlled Subsurface Safety Valves (SCSSV)*:
    - WireLine Retrievable valves (WLR)
    - Tubing Retrievable valves (TR) (or Tubing Mounted: TM)

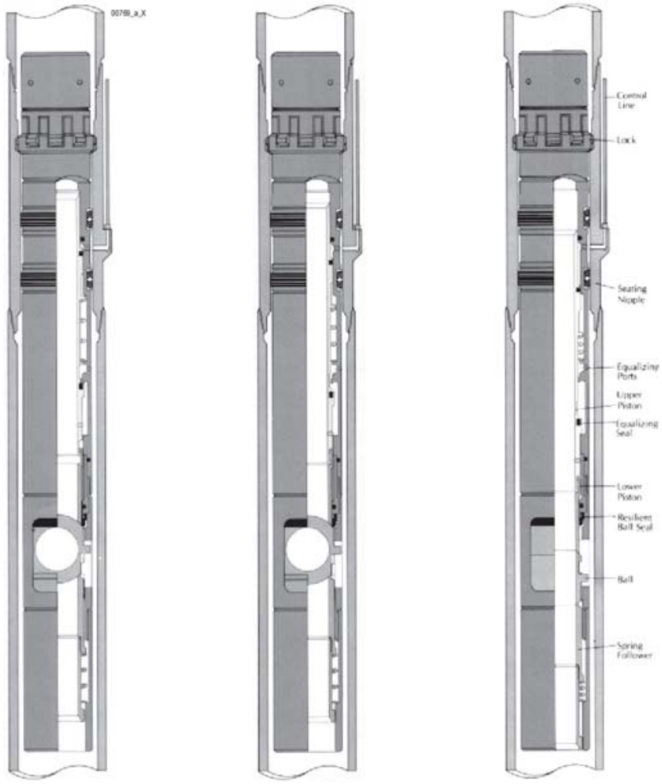
    & also:
    - SubSurface Tubing-Annulus safety valves (SSTA)*

Surface Controlled Subsurface Safety Valve (SCSSV)

WLR

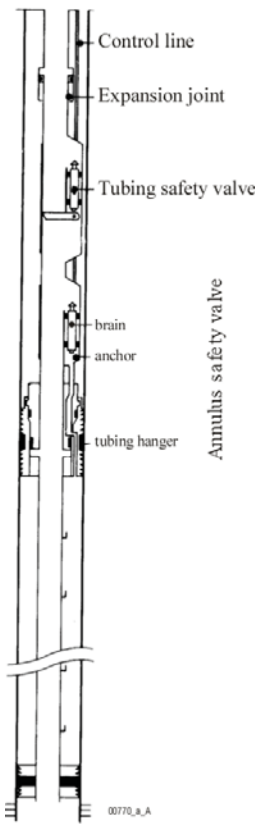
TR

Equalising WLR SCSSV



Closed **Equalising** **Open**

Tubing-Annulus Subsurface Safety valve (SSTA)



SCSSV testing procedure - Implementation

- **Test:**
  - With the well pressure
  - or
  - On plug
- **Implementation:**
  - Well shut in (wing valve)
  - SCSSV closure
  - Bleed of at the wellhead to have:
    - The atmospheric pressure
    - or
    - The wanted ΔP
  - Observation
  - If SCSSV with equalising device:
    - Opening the SCSSV by pressurising the control line
    - 0bservation
    - And, if test "on plug", plug removing
  - If not:
    - Pumping in the tubing to equalise pressure
    - And ditto

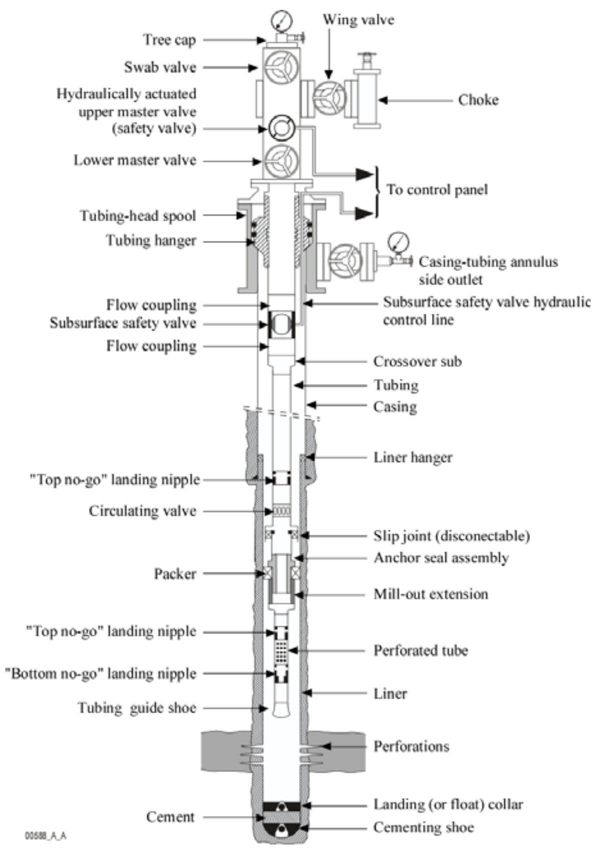
Testing criteria & periodicity

- **Testing criteria (API RP 14B):**
  - Liquid: 400 cc/min i.e. 24 l/h [≈ 0.1 gal/min or 14 . 10^{-3} scfm]
  - Gas: 15 scfm [≈ 425 l/min or 25.5 m^3/h]
- **Testing periodicity:**
  - Each time the valve has been removed
  - Every year
  - Special rules if simultaneous activities (drilling, completion, production, etc.)

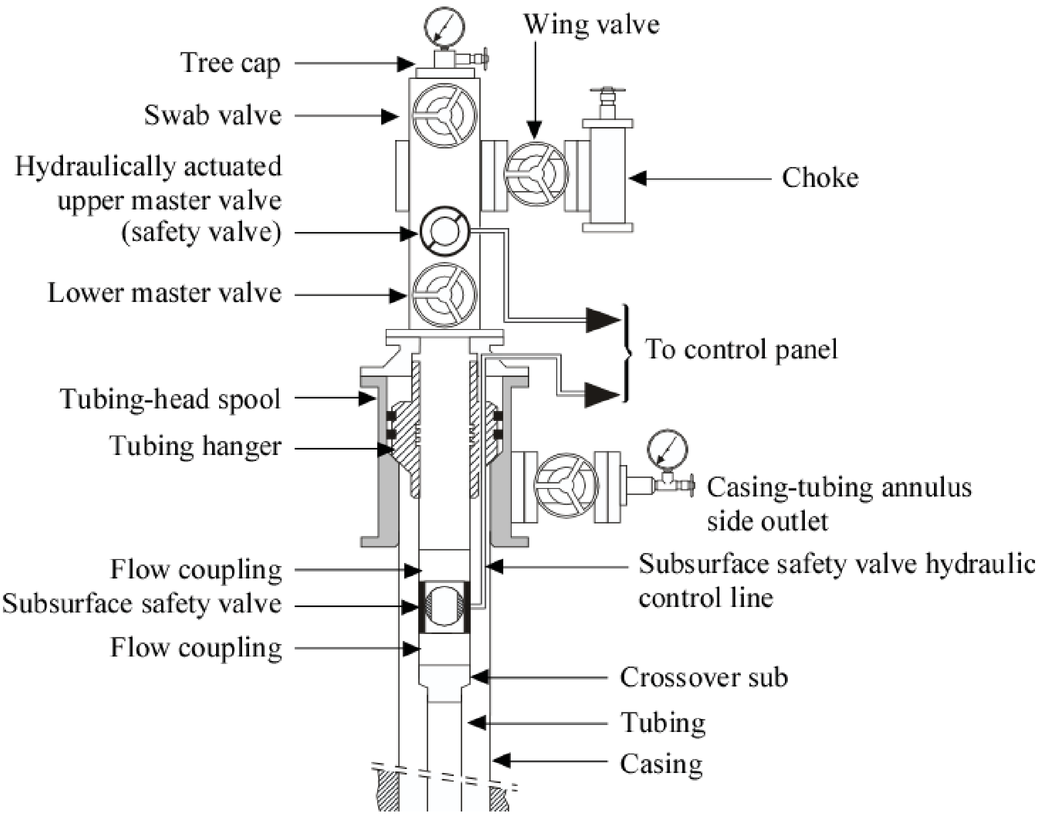
Synthesis

example of equipment for a naturally flowing well

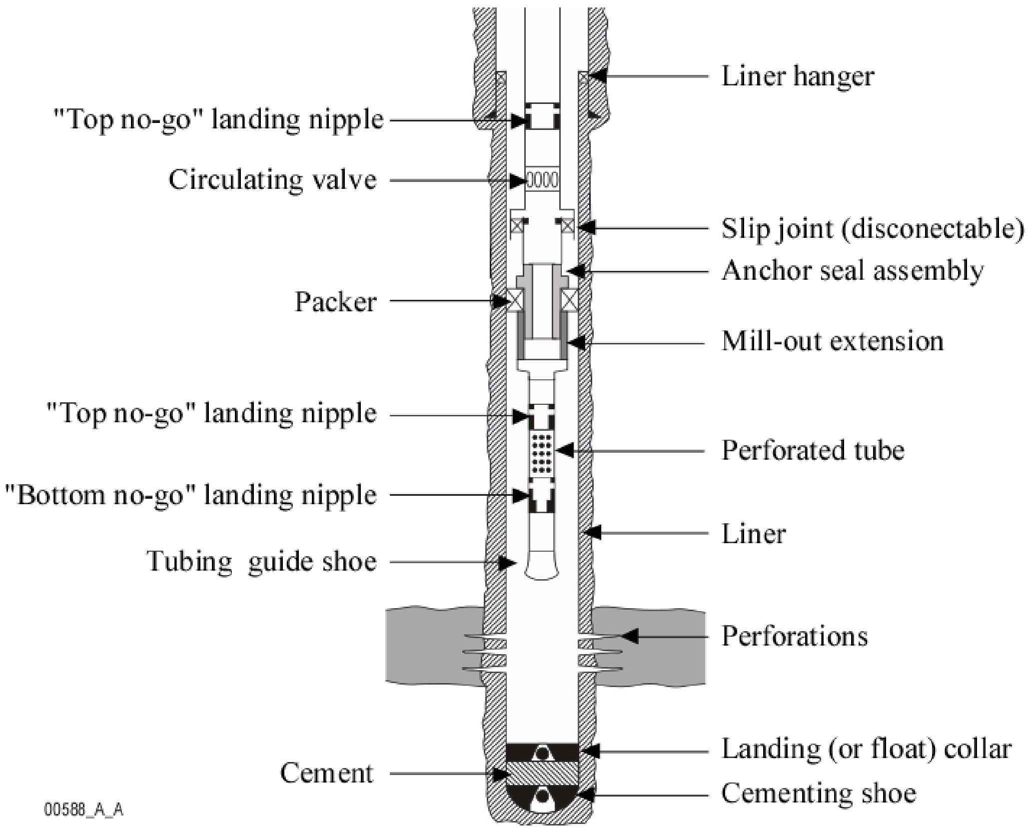
Synthesis: example of equipment for a naturally flowing well



Example of equipment for a naturally flowing well: upper part



Example of equipment for a naturally flowing well: lower part



Running procedure

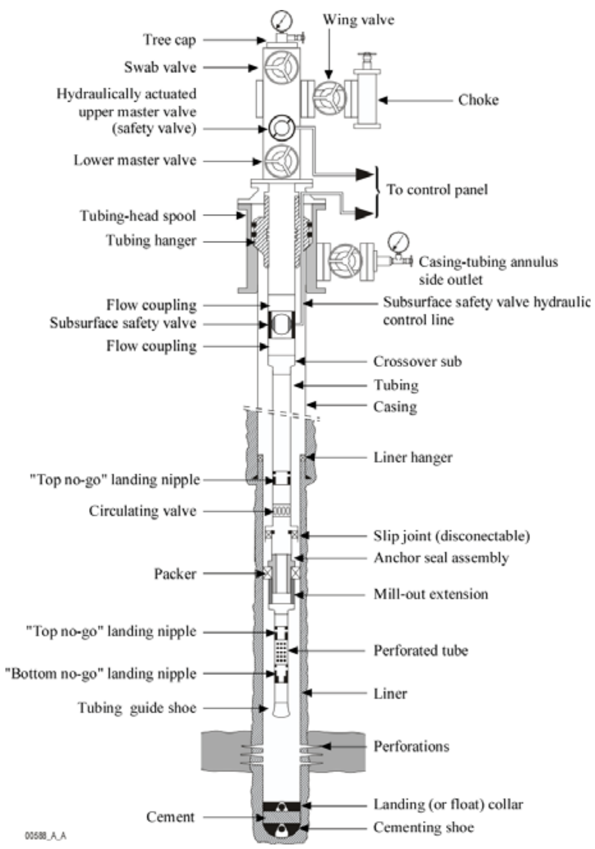
Running procedure function of:

- Selected pay zone-borehole connection and, for cased hole, when perforating is done
- "Special" operations on the pay zone (sand control, stimulation job)
- Number of level to be produced separately
- Chosen equipment : type of packer, etc.

Selected case

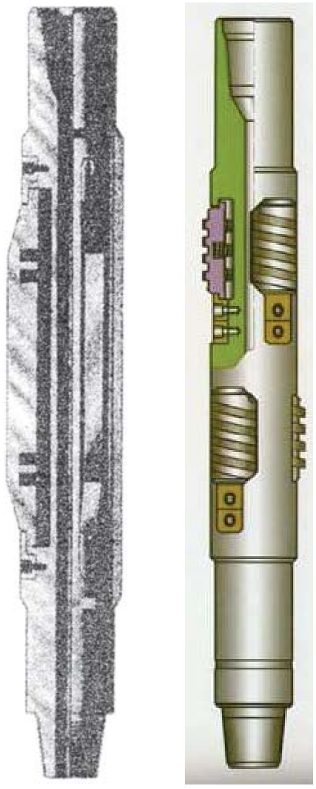
- **Pay zone- borehole connection:**
  - Cased hole, perforation done before equipment installations
  - No "special" operations, one single level
- **Equipment*:**
  - Permanent packer run beforehand
  - Circulating device
  - "WLR" SCSSV

Running procedure: selected case



Preliminary operations

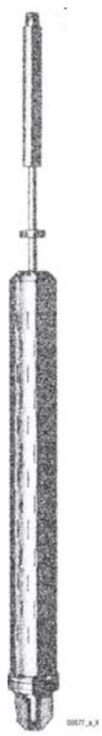
- **If needed, reconditioning the wellhead:**
  - Tubing-head spool installation
  - Rams adaptation
- **Checking the borehole:**
  - Tagging cement
  - Cleaning the casing wall*
  - Displacing completion fluid
- **Cased Hole Logging:**
  - Correlation log & Cement bond log
  - Supplementary logs for reservoir purposes
- **If needed, reconditioning the BOPs:**
  - Rams corresponding to tubing
- **Perforating**



Scrappers

Running subsurface equipment (case of a permanent packer set prior to running the tubing)

- **Setting the packer (and below-packer extension):**
  - Choice of the setting depth
  - Setting on wireline or on drillpipes
  - If wireline setting : junk basket + gauge ring run*
- **Assembling and running the equipment (and testing while running in):**
  - Safety
  - Removing wear bushing
  - Picking-up and final checking of the equipment
  - Screwing
  - Possibly, testing while running in the equipment

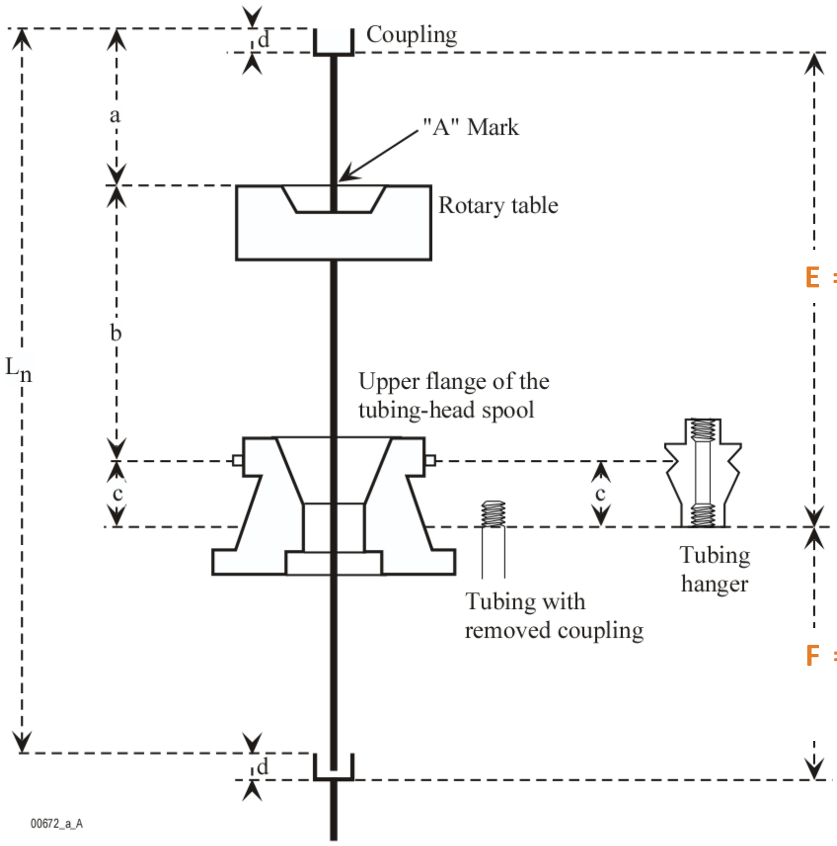


Junk catcher

Running subsurface equipment (case of a permanent packer set prior to running the tubing – cont.)

- **Inserting the scssv landing nipple and continuing to run in:**
  - Landing nipple protected by a separation sleeve
  - Continuing to run in, usually without the control line
- **Spacing out the production string:**
  - Necessity of spacing out
  - Locating the packer
  - Spacing out calculation*

Spacing out calculations



$E = (a + b + c) – (d)$

$F = (L_n + d) – (a + b + c)$

$= L_n – E$

Running subsurface equipment (case of a permanent packer set prior to running the tubing – cont.)

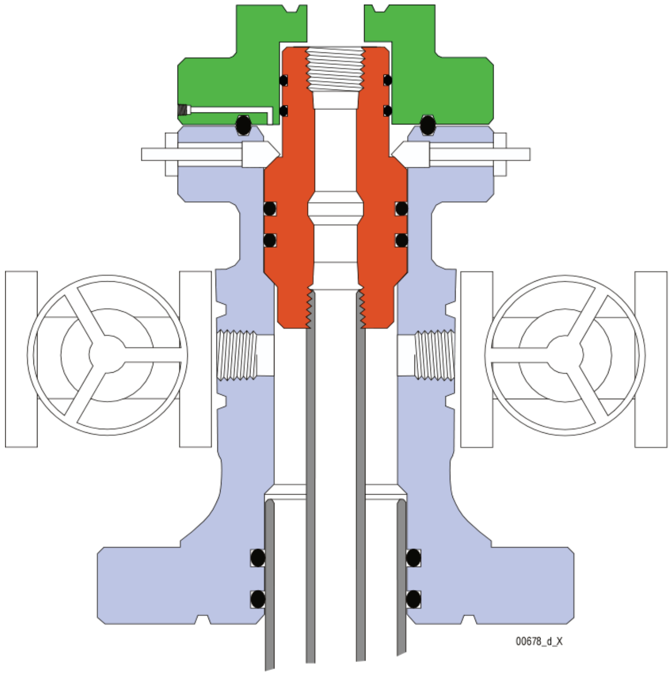
- **Completing tubing equipment and landing the tubing:**
  - Pulling the tubing up to the SCSSV landing nipple
  - Connecting the control line
  - Running in again and inserting selected tubings and pup joints
  - Screwing the tubing hanger, connecting the control line on it
  - Connecting the landing pipe
  - Landing of the tubing hanger in the tubing head spool
- **Testing the production string (and the annulus)**

Main differences in running procedure in the case of an hydraulic packer (run in directly on the tubing)

- **Assembling and running the equipment (and testing while running in)**
- **Inserting the SCSSV landing nipple and finishing to run the equipment**
- **Partial testing of the production string**
- **Setting the packer and ending installation of the bottom hole equipment:**
  - Positioning tubing hanger
  - Setting packer
  - Landing tubing hanger (if not already done)
  - Testing tubing (& annulus)

Installing the Christmas tree

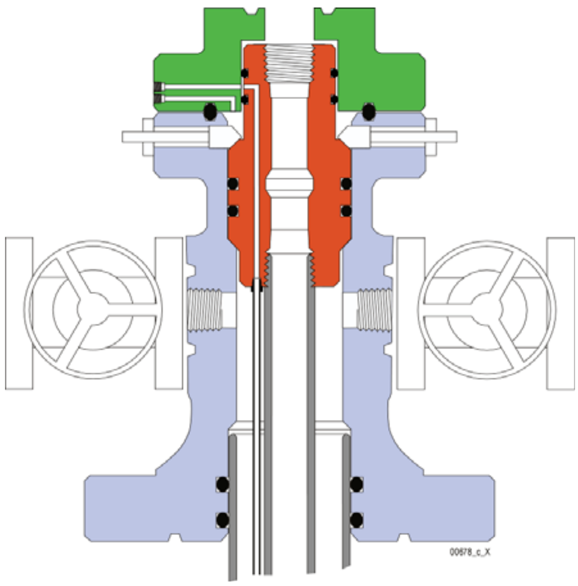
- **Replacing the BOPs by the Christmas tree:**
  - Safety
  - Unbolting BOPs
  - Mounting adapter and Christmas tree
- **Testing the production wellhead***



Testing
(adaptor being in place)

Bringing the well on stream

- **Pumping in annular and clearing fluids:**
  - Opening circulating valve
  - Displacing fluids
  - Closing circulating device and pressure testing
- **Setting and testing the SCSSV**
- **Clearing the well:**
  - Choice of the flowrate and duration
  - Beware: bleed off or watch on places where liquid is trapped*



Tubing head spool assembly: Details on sealing elements

Moving out the rig & Final completion report

- **Moving out the rig:**
  - After putting back the well in safe condition:
    - Mechanical safety barriers
- **Final completion report:**
  - Identification of the well
  - Purpose
  - Important facts or event and results obtained
  - Final state of the well
  - Detailed account of the operations

Intelligent completion

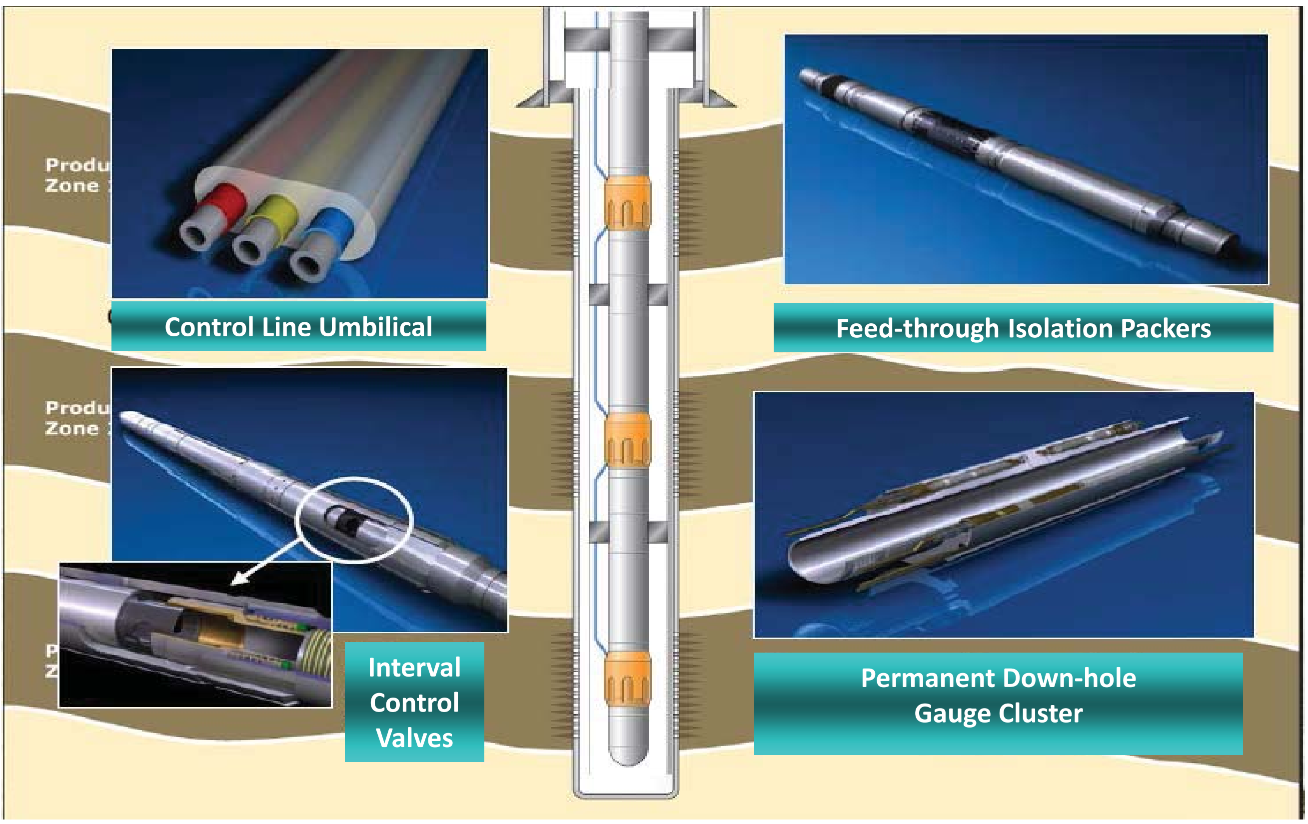
Principle

- **For each zone*:**
  - 1 valve with several positions actuated from the surface:
    - Open, closed and x positions
  - 1 monitoring P, T tubing (and annulus):
    - Bounded up with the valve

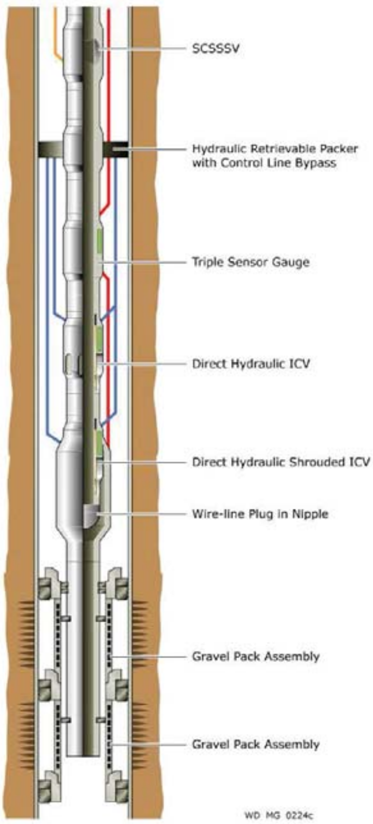
    or
    - Separate mandrel

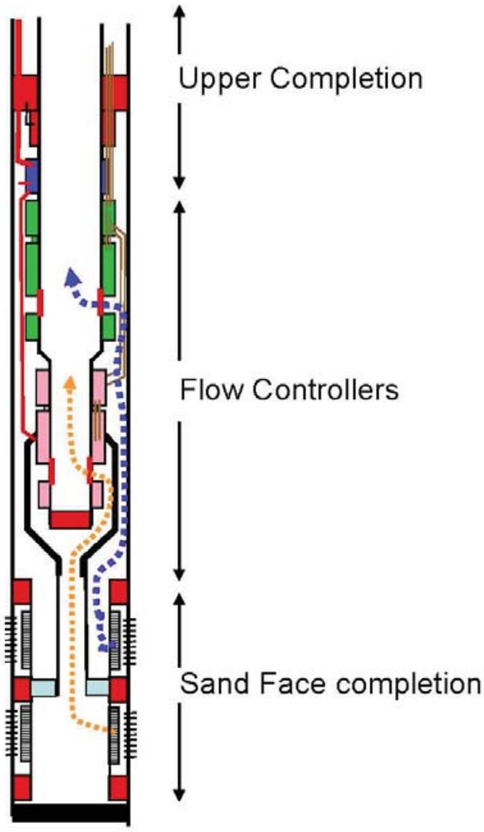
Note: If monitoring P annulus (in addition to P tubing):
- Knowledge of the flow rate through the valve from ΔP (calibration)
- Possibility of making a build-up (well test)

Elements of intelligent completion

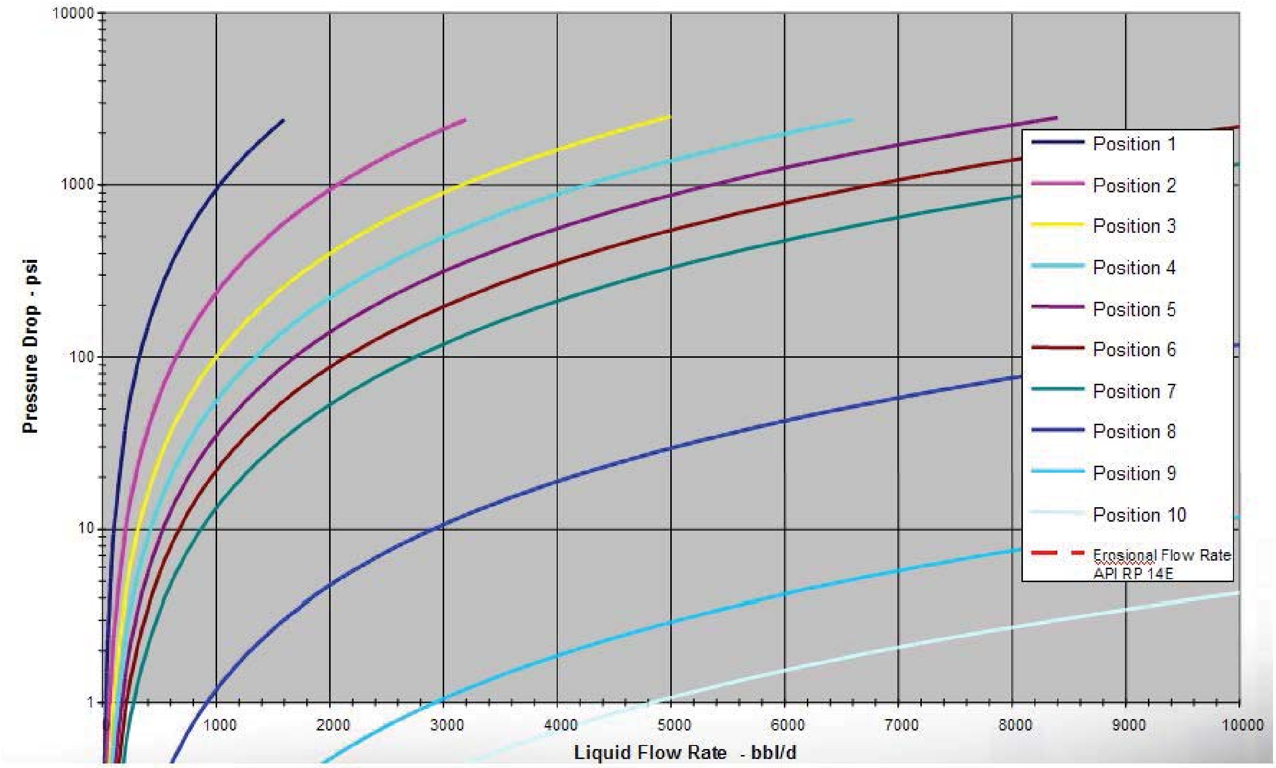


Intelligent completion with sand control

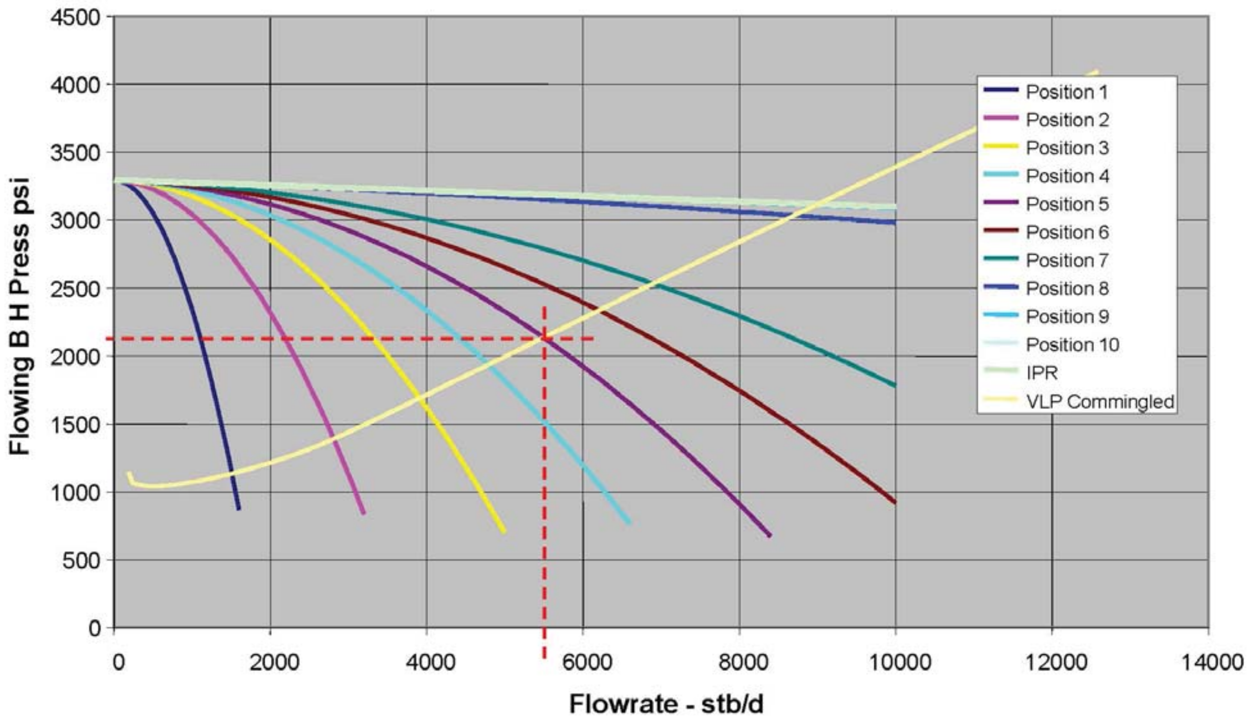




ICV Pressure drop versus Liquid flow rate for each ICV setting position



IPR combined with ICV Pressure drop at each ICV setting position



Principle (cont.)

- **Supplementary tools:**
  - Metering:
    - Venturi meter (slick line retrievable):
      - In front of each zone
      - Or, common system at the top and difference by closing / opening the different zones
  - Gradiomanometer, etc.
- **But:**
  - Cost
  - Reliability
  - Running in very long:
    - Hydraulic and electric connections
    - …

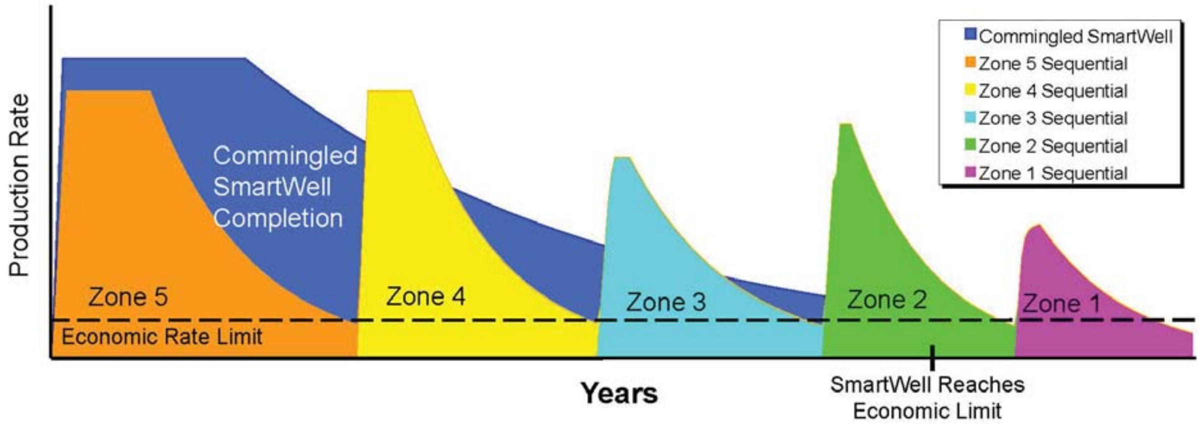
Principle (cont.)

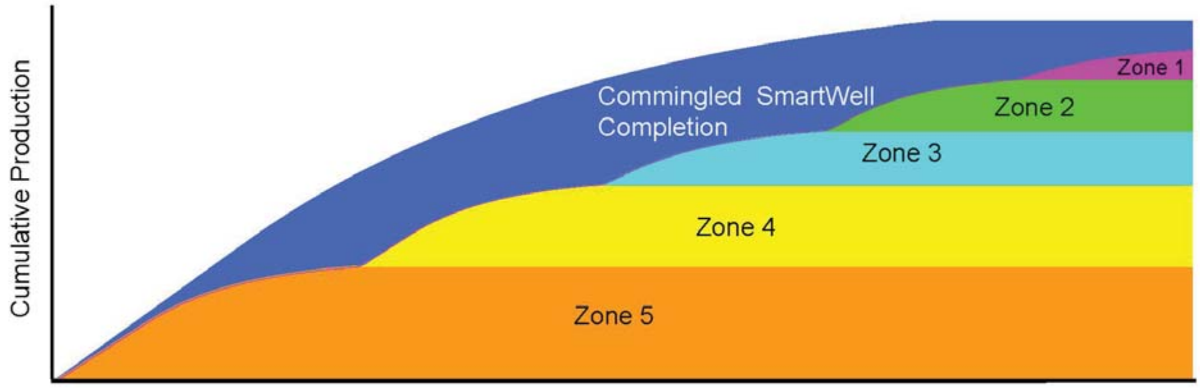
- **"Less" intelligent version:**
  - Valves:
    - Only with 2 positions (open/closed)
    - Without sensors
  - And, usually, no "mandrel with sensors " combined with
- **1st intelligent completion run in:**
  - September 97:
    - By SAGA
      - P18 well, Snorre A
    - SCRAMS system
    - Has been working 6 months

Main applications

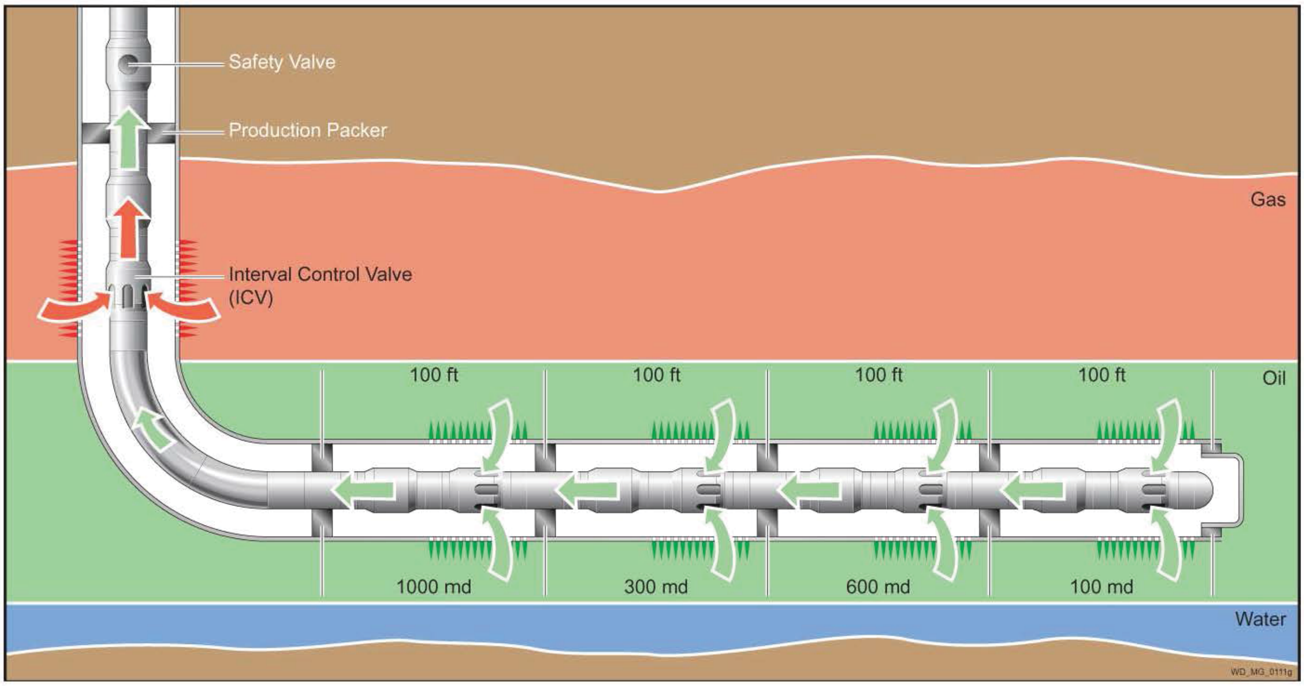
- **Commingled production or Sequential production** *
- **Auto gas-lift** *
- **To manage drawdown**
- **To control water or gas coning**
- **To control water, gas or steam injection**
- **…**

Commingled production versus Sequential production





Auto gas-lift



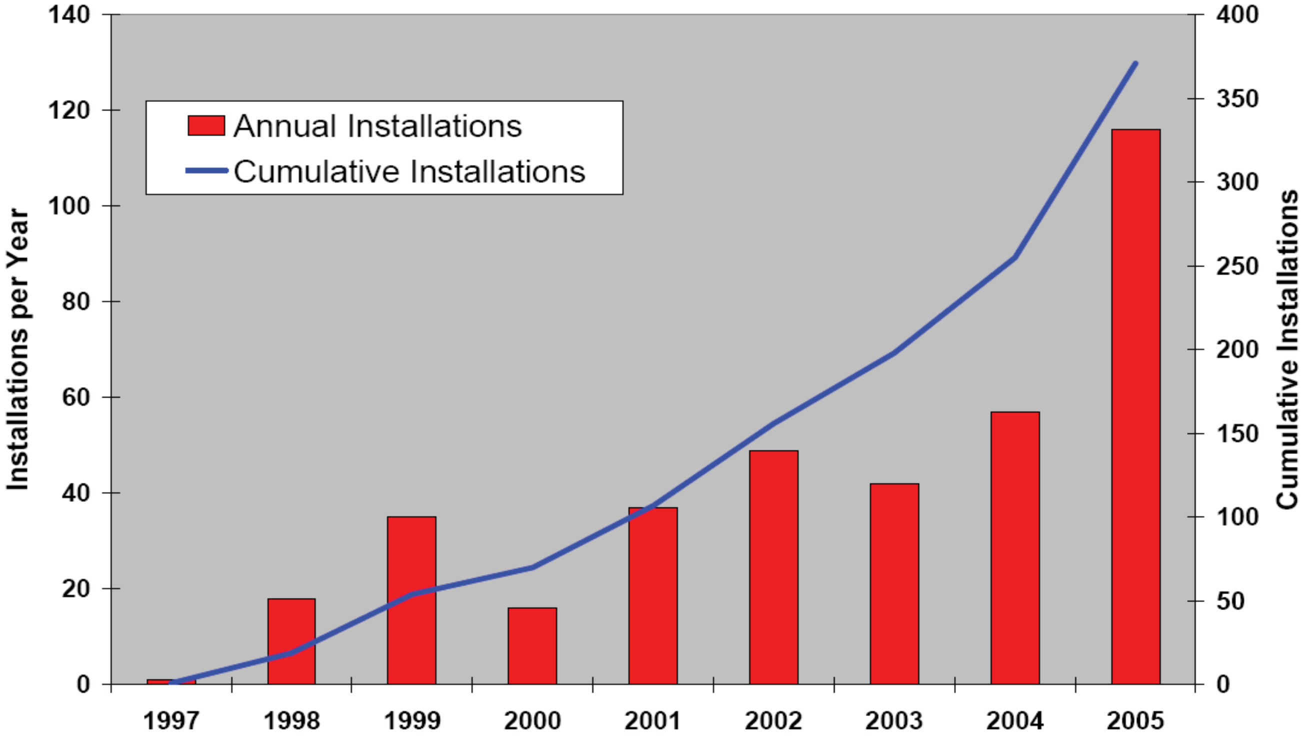
Attractive fields for intelligent completion

- **Deep offshore development:**
  - Well number optimization (multi-zones completions)
  - Well testing without re-entries
- **Multilateral wells:**
  - Better control of each branch, of cross-flow
  - Make easier well neutralization, if necessary
- **Water and/or gas entry control:**
  - So better recovery ratio
- **Injection well:**
  - Better allocation of the injection, so better recovery ratio

Attractive fields for intelligent completion (cont.)

- **Better recovery:**
  - Refer to previous points
- **Better reservoir knowledge (appreciation phases, early production, production):**
  - Interference measurement
  - Water level behavior
  - Effect of water injection
- **⇒ More and more intelligent completions***

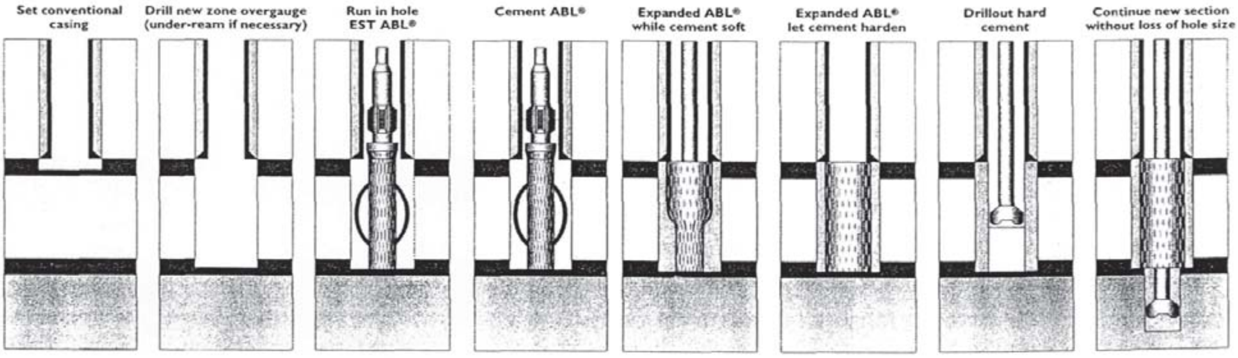
Number of intelligent completion installations in the world



Miscellaneous

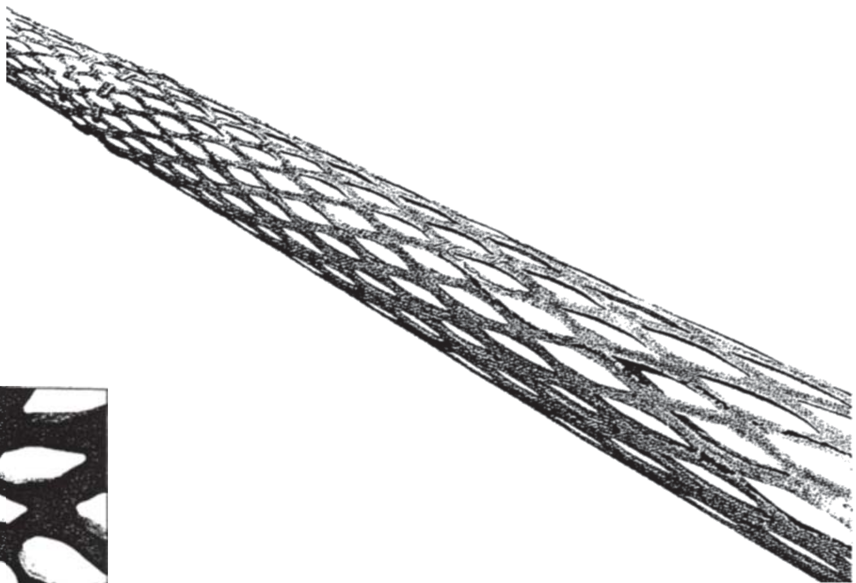
- Alternative Borehole Liner*
- Expandable Completion Liner*
- Expandable Sand Screen*

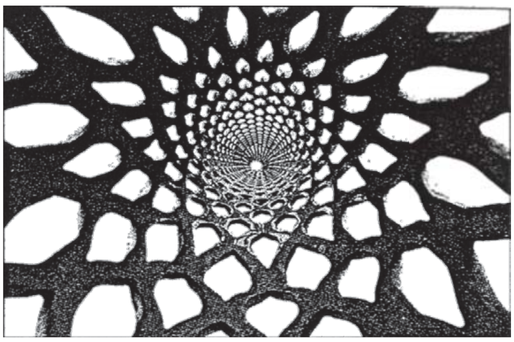
Alternative borehole liner (Petroline)



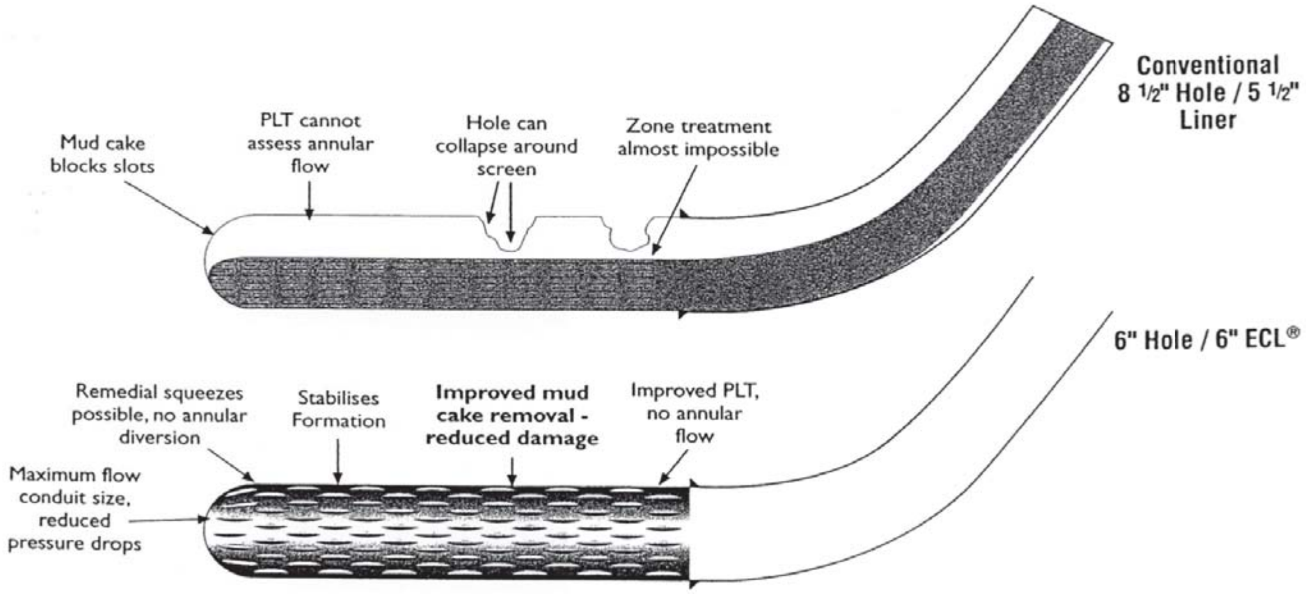
Allows the selective isolation of problem section without loss of hole size

Expandable Completion Liner (Petroline)

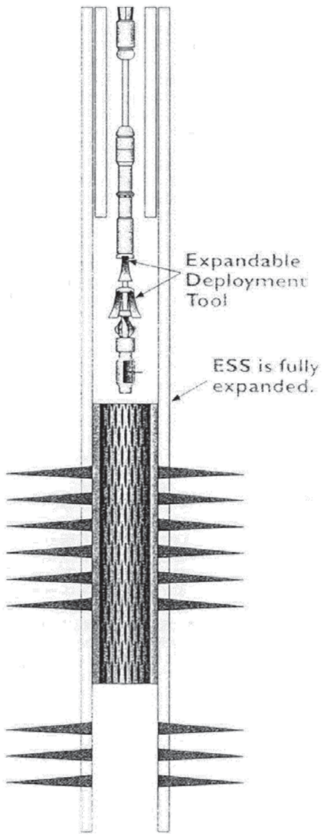


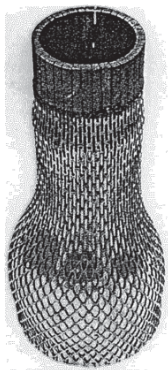


Expandable Completion Liner (Petroline) (cont.)

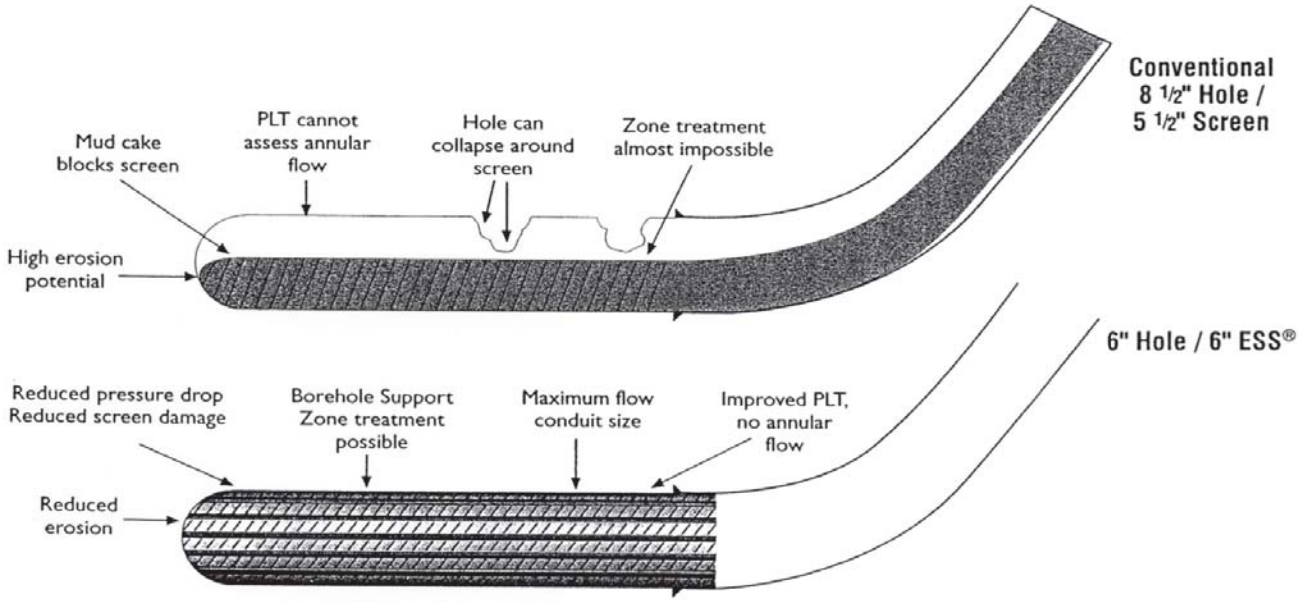


Expandable Sand Screen (Petroline)





Expandable Sand Screen (Petroline) (cont.)



Artificial lift

Content

- Pumping
- Gas lift
- Choosing an artificial lift process

Pumping

Pumping

- Principle & types of pumping
- Sucker rod pumping
- Centrifugal pumping with an Electric Submersible Pump (ESP)
- Other methods of pumping
- Measurements on pumped wells
- Defining a pump installation

Principle of pumping

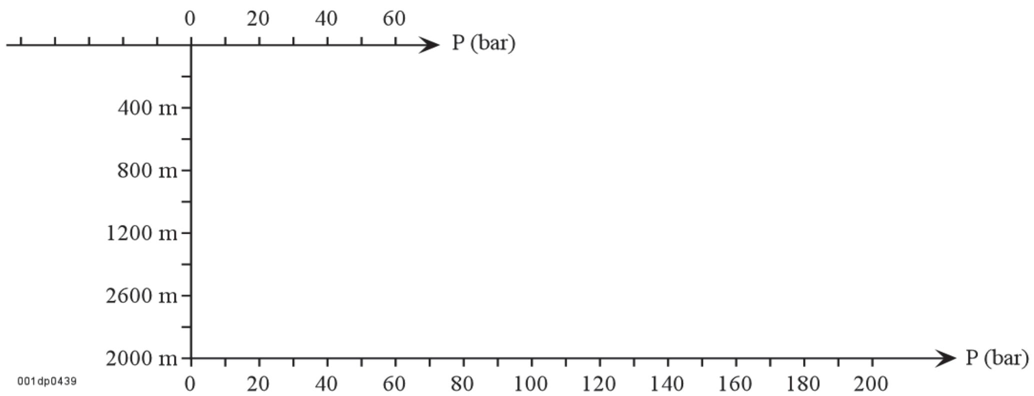
Principle :

- Energy input *
- Pump placed below the dynamic level
- Usually, no packer

Increase of pressure required from the pump (ΔPpump)

- **Data:**
  - P_R = 190 bar at Z = 2000 m
  - PI = 5 m³/j/bar
  - Gradient_{static} = 0,075 bar/m
  - $\text{Gradient}_{flowing}$ = 0.08 bar/m
  - Q_{wanted} = 300 m³/j
  - WHP_{wanted} = 20 bar

- **Questions:**
  - WHP_{shut} =
  - For $Q = Q_{wanted}$:
    - ΔP_R =
    - $BHP_{flowing}$ =
    - "$WHP_{no\ art.\ lift}$" =
      =
    - ΔP_{pump} =



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Types of pumping

- **Types of pumping:**
  - Sucker rod pumping
  - Centrifugal pumping with an Electric Submersible Pump (ESP)
  - Hydraulic pumping:
    - Plunger pump
    - Jet pump
    - Centrifugal turbine pump
  - "Progressive" or "progressing" cavity pump

Sucker rod pumping

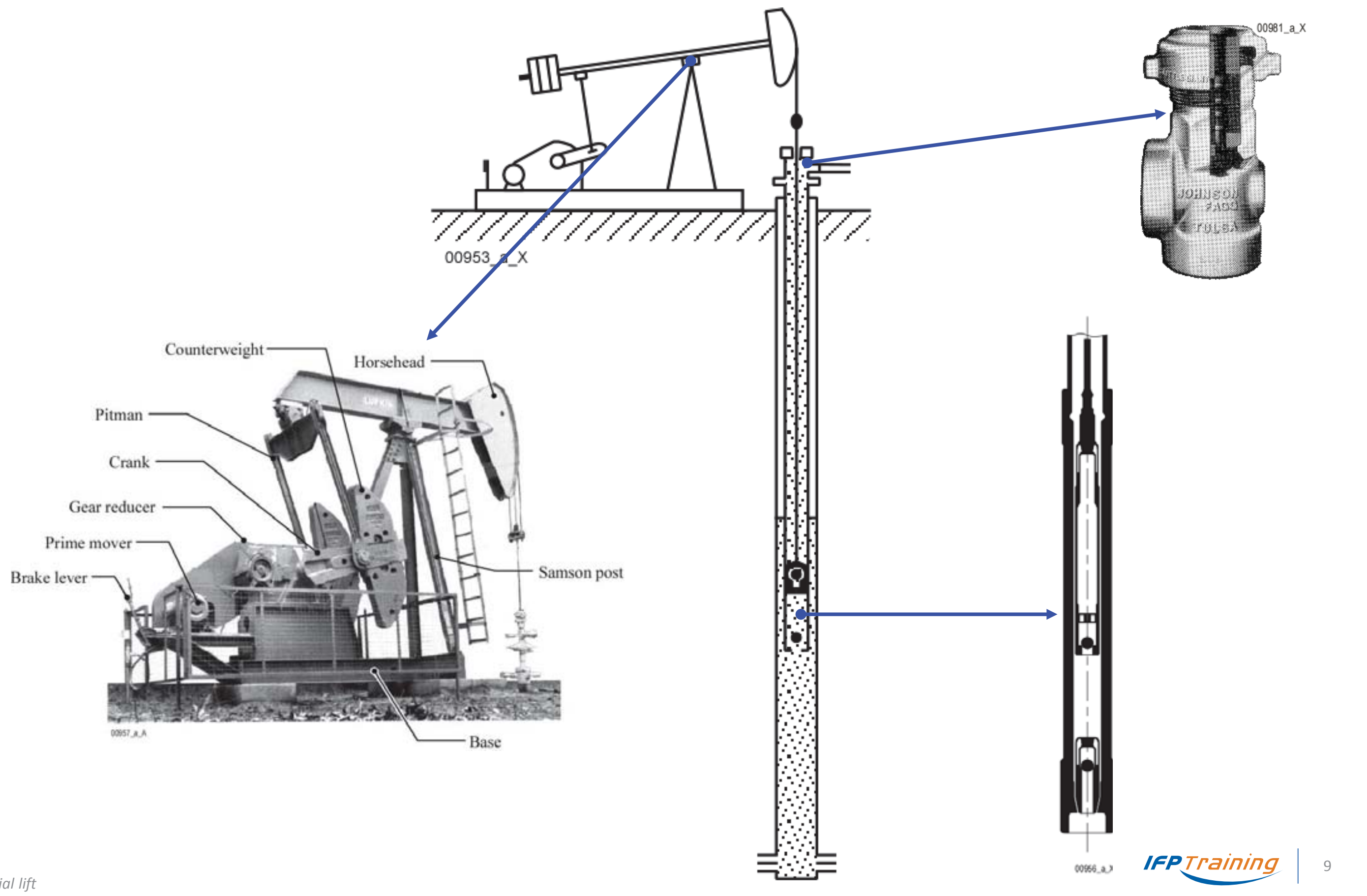
- **Basic configuration: ****
  - Positive-displacement pump: cylinder & plunger
  - Rods
  - Pumping unit: PU
- **Sucker rod pumping cycle: ****
  - Upstroke
  - Downstroke
- **Flow rate (Q):**
  - Q = S x N x A

    with: S = stroke

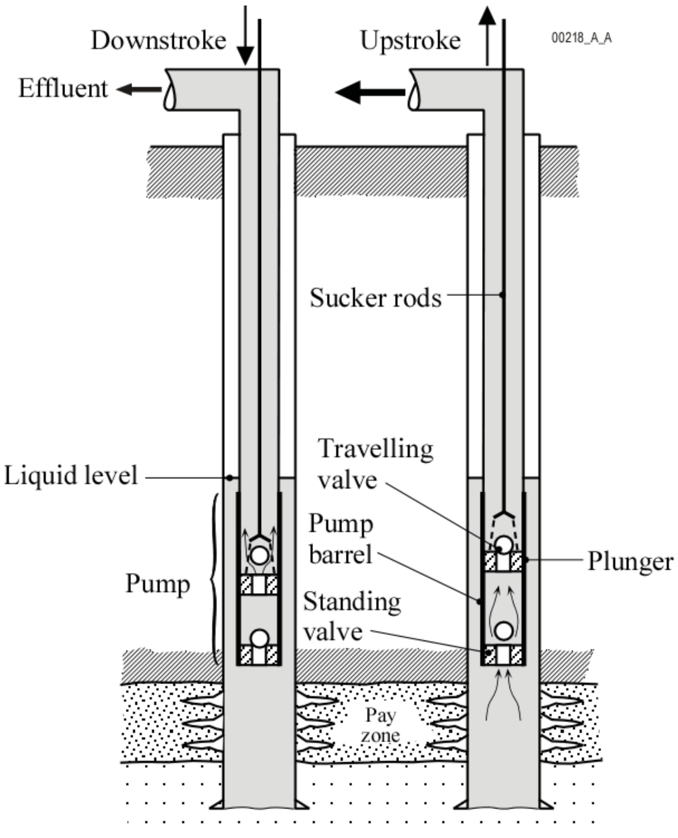
    N = number of stroke per time unit (pumping rate)

    A = area of the plunger
  - Efficiency factor

Basic configuration of a sucker rod pumping system



Sucker rod pumping cycle

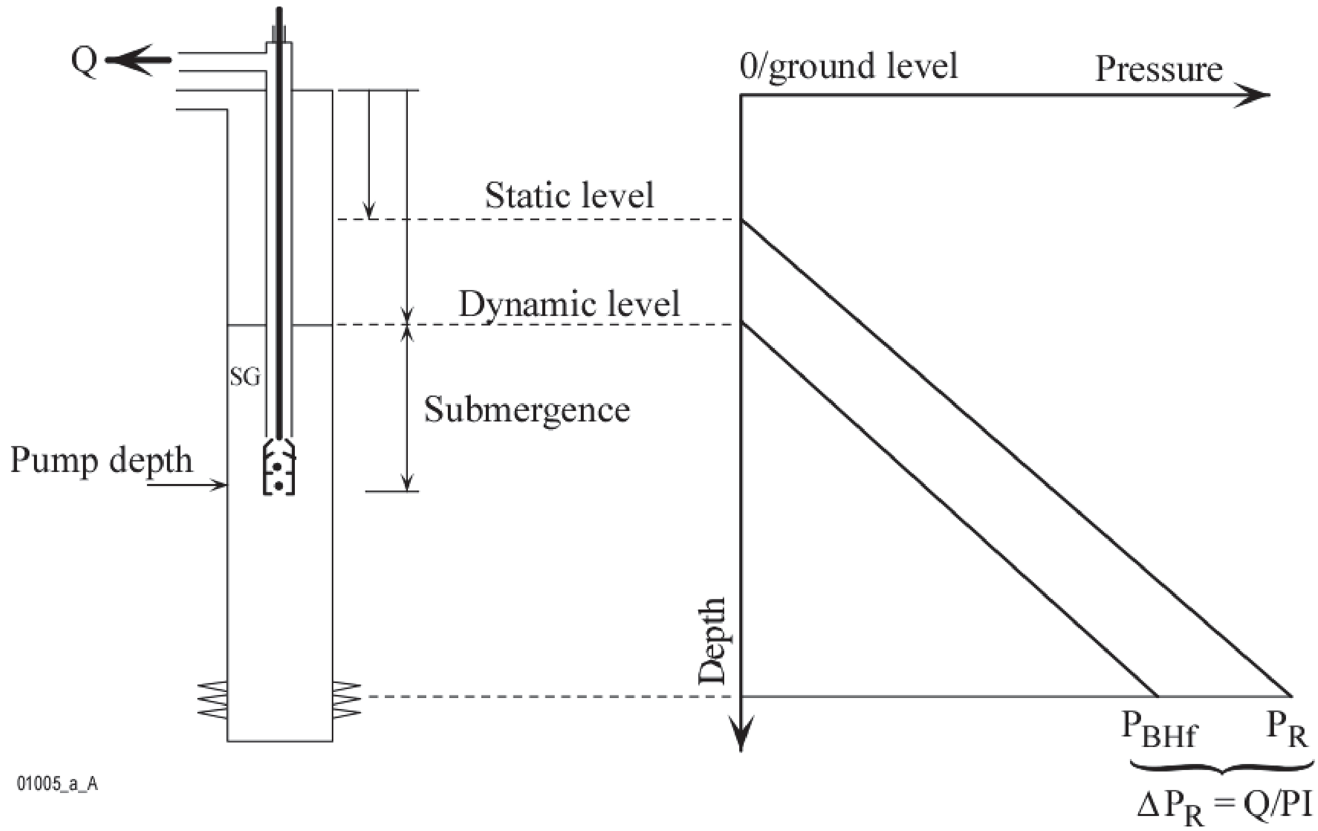


	Weight supported by : rods	Weight supported by : tubing
during upstroke	rods + "fluid"	tubing
during downstroke	rods	tubing + "fluid"

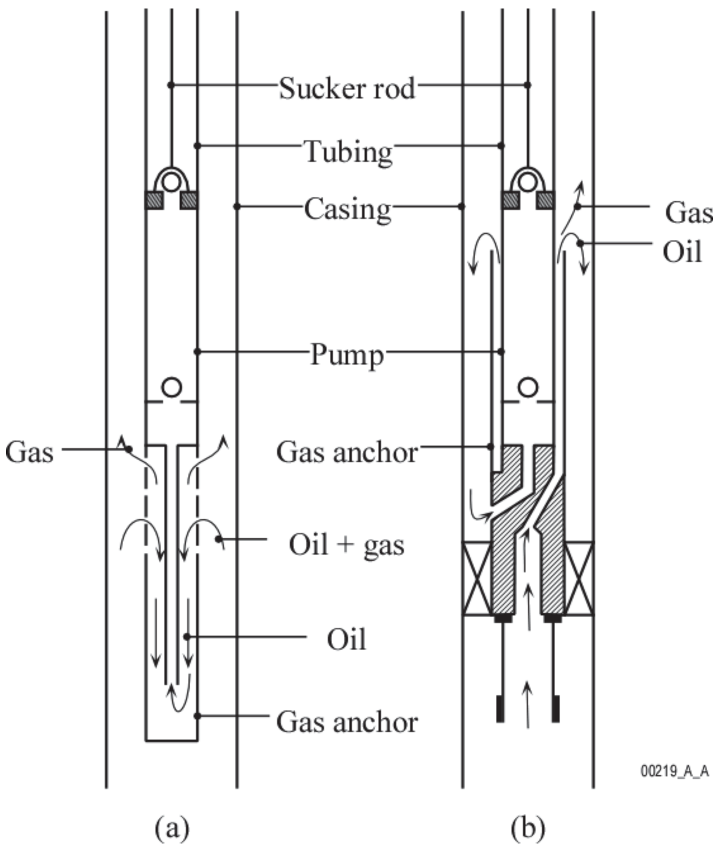
Choosing pumping parameter

- **Operating problems:**
  - Dynamic level*
  - Free gas*
  - Tubing breathing and buckling*
  - Fatigue
    $\Rightarrow$ tapered rod string*
  - Resonance

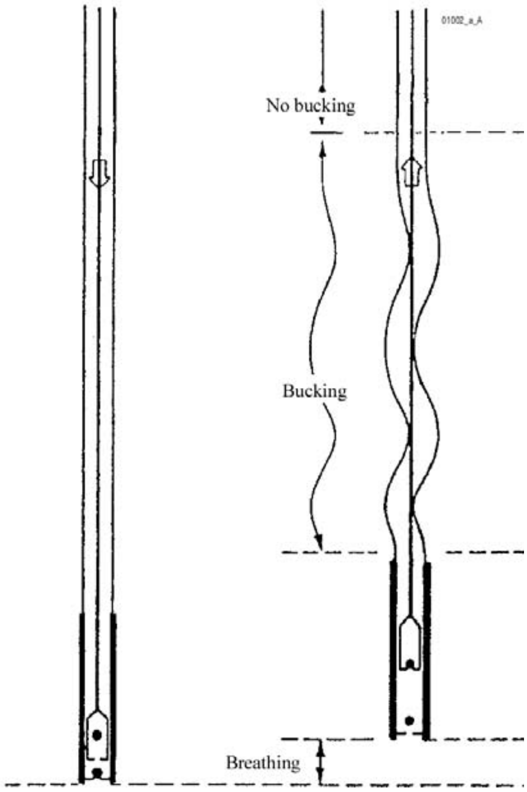
Dynamic level & pump depth

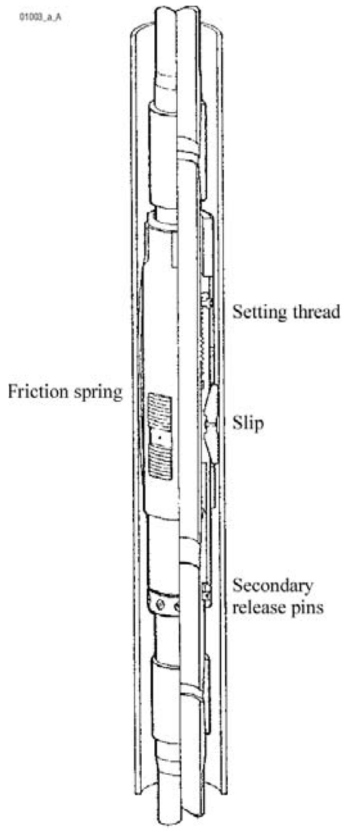


Gas anchor



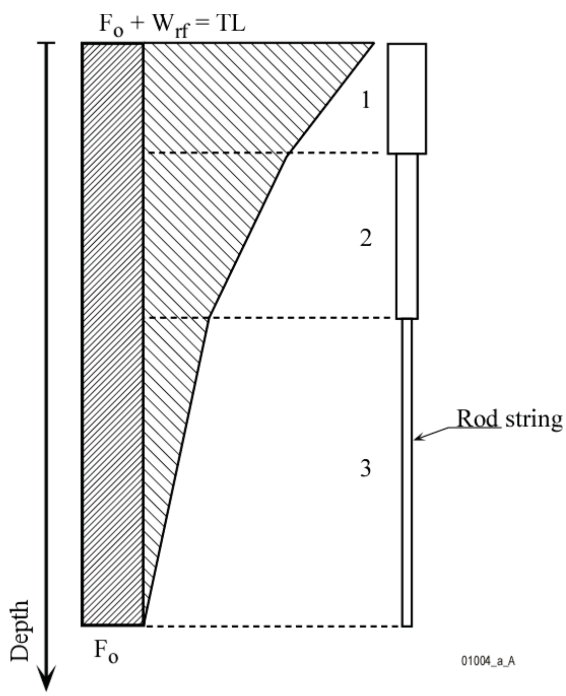
Effect of pumping cycle on the tubing & Mechanical anchor





Fatigue & tapered rod string

- **Fatigue depends on:**
  - Maximum tension Tmax :
    - Tmax = Rod weight
      +
      Fluid weight
  - Ratio between minimum tension Tmin and maximum tension Tmax:
    - Tmin = Rod weight
  - Number of cycle



Tension supported by a tapered rod string

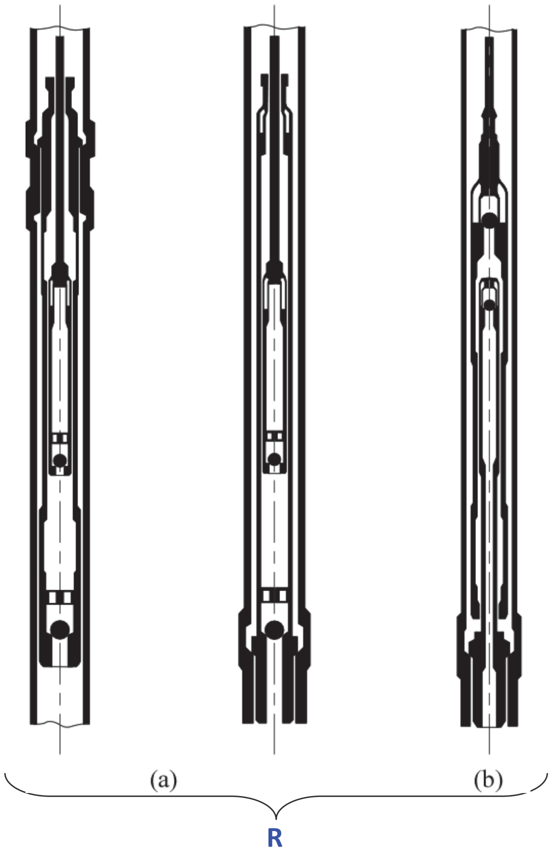
Choosing pumping parameter (cont.)

- **Depth of the pump**
- **Pumping parameters:**
  - Plunger diameter
  - Pumping rate
  - Stroke

Downhole equipment

- **Special equipment for the tubing:**
  - Tubing anchor (for memory)
  - Gas anchor (for memory)
- **Sucker rod pumps:**
  - API spec 11 Ax pump designation*:
    - R pumps (rod pumps or inserted pumps)
    - T pumps (tubing pumps)
  - Basic pump bore:
    - 1"1/4, 1"1/2, 1"3/4, 1"25/32, 2", 2"1/4, 2"1/2, 2"3/4

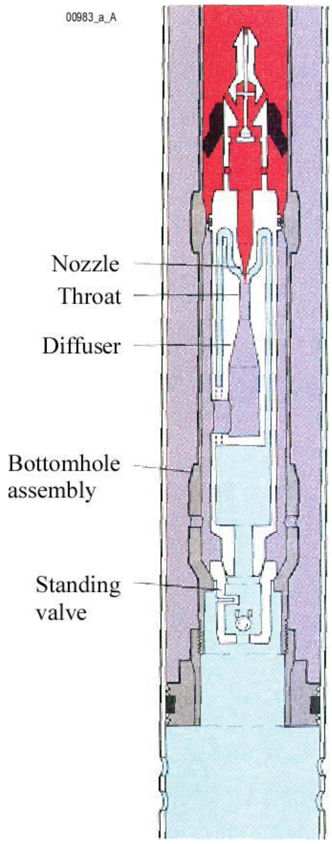
R & T pumps (Rod & Tubing)



Rod pump seating assembly

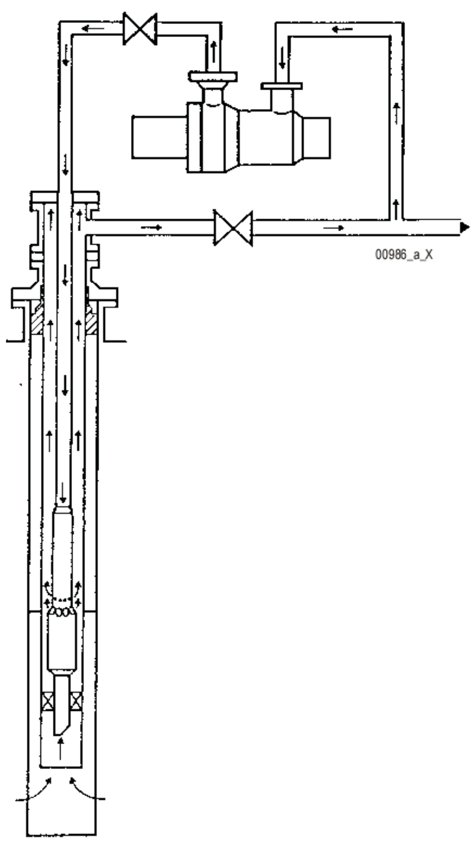
Hydraulic pumping (cont.)

- Jet pumps



Hydraulic pumping (cont.)

- Turbo-pums

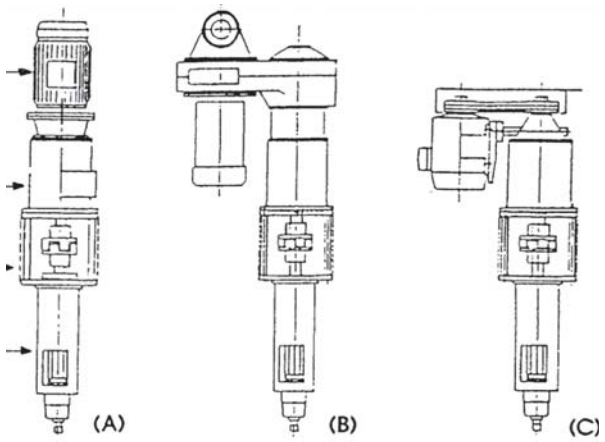


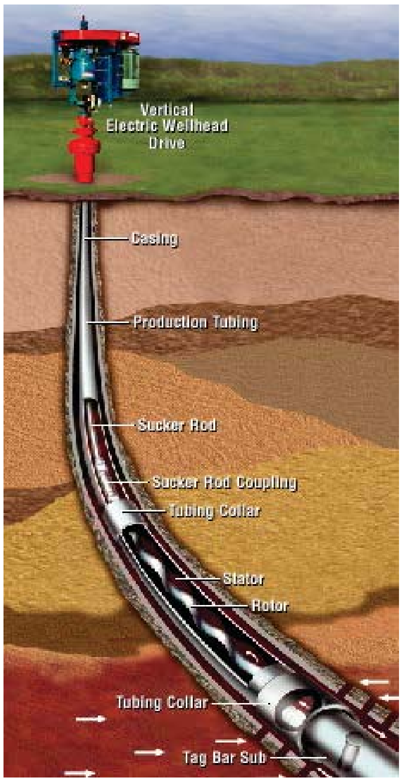
"Progressives" or "progressing" cavity pumps

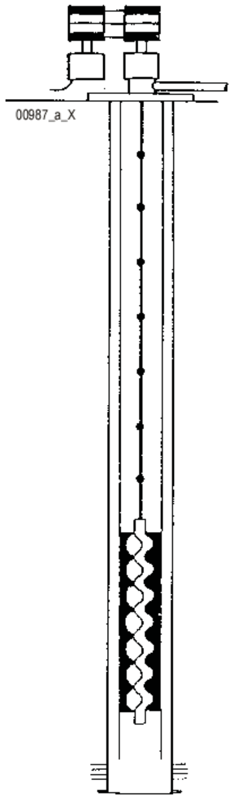
▶ Principle *

Various driving types:

Electrical Mechanical Per belt





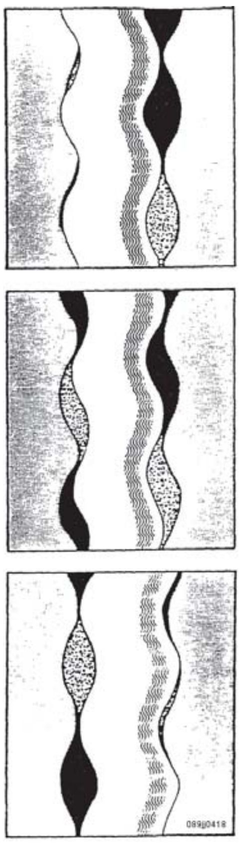


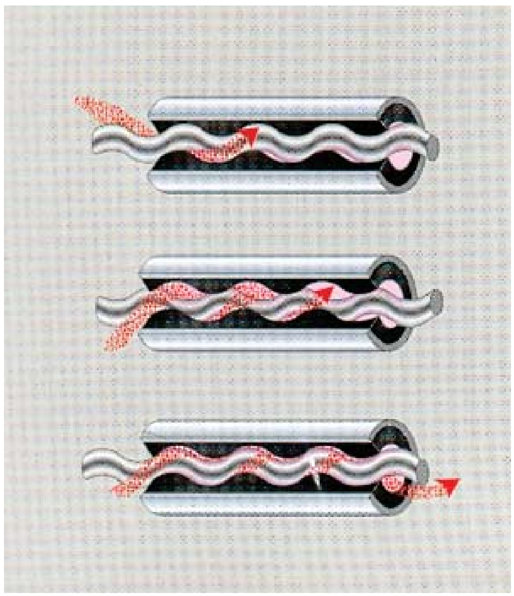
Principle of a progressive cavity pump

"Progressives" or "progressing" cavity pumps (cont.)

▶ Movement of the fluid *

The geometry of the elastomeric stator and eccentric metallic rotor assembly is such as it forms a series of cavities parted one from the other.
When the rotor turns, these cavities move axially (progress), inducing a pumping movement of the fluid entered in these cavities on the intake side.
These « progressives » cavities being parted, PCP are volumetric pump.





Movement of the fluid

"Progressives" or "progressing" cavity pumps (cont.)

Example of pump performance (1/2):

Series	Pump Model	ISO Code	Flow at 500 RPM		Head Capability	
			m3/j	bfpd	m	ft
2 3/8" EUE	15 TP 1200	15/12	16	100	1200	4000
	30 TP 600	30/6	27	168	600	2000
	30 TP 1300	30/13	27	168	1300	4250
	30 TP 2000	30/20	27	168	2000	6600
	80 TP 1200	80/12	85	536	1200	4000
	80 TP 1600	80/16	85	536	1600	5220
2 7/8" EUE	60 TP 1300	60/13	66	417	1300	4250
	60 TP 2000	60/20	66	417	2000	6600
	60 TP 2600	60/26	66	417	2600	8500
	100 TP 600	100/6	109	684	600	2000
	100 TP 1200	100/12	109	684	1200	4000
	100 TP 1800	100/18	109	684	1800	5900
	240 TP 900	240 /9	238	1494	900	2950
3 1/2" EUE	120 TP 2000	120/20	122	770	2000	6600
	120 TP 2600	120/26	122	770	2600	8500
	200 TP 600	200/6	196	1232	600	2000
	200 TP 1200	200/12	196	1232	1200	4000
	200 TP 1800	200/18	196	1232	1800	5900
	300 TP 800	300/8	300	1885	800	2600

Models are designated by two numbers. The first one is an approximation of the capacity in m^3/d at 500 rpm and zero head, the second one indicates the nominal head capability in meters.
Series are designated by the size of the API stator thread

"Progressives" or "progressing" cavity pumps (cont.)

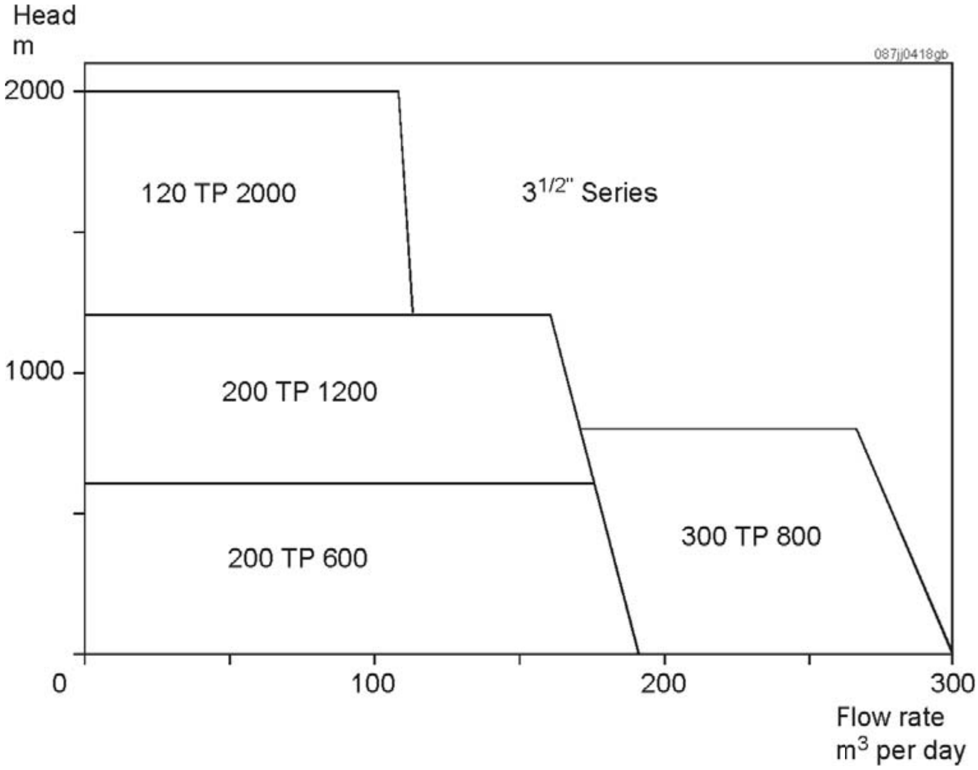
Example of pump performance (2/2):

Series	Pump Model	ISO Code	Flow at 500 RPM		Head Capability	
			m3/j	bfpd	m	ft
4" NU	180 TP 1000	180/10	190	1193	1000	3300
	180 TP 2000	180/20	190	1193	2000	6600
	180 TP 3000	180/30	190	1193	3000	9850
	225 TP 1600	225/16	225	1410	1600	5300
	225 TP 2400	225/24	225	1410	2400	7900
	300 TP 1200	300/12	300	1885	1200	4000
	300 TP 1800	300/18	300	1885	1800	5900
	400 TP 900	400/9	400	2515	900	2950
	400 TP 1350	400/13.5	400	2515	1350	4450
	600 TP 600	600/6	600	3770	600	2000
	600 TP 900	600/9	600	3770	900	2950
	840 ML 500	840/5	840	5280	500	1650
	840 ML 1000	840/10	840	5280	1000	3300
	840 ML 1500	840/15	840	5280	1500	4900
5" CSG	430 TP 2000	430/20	430	2703	2000	6600
	750 TP 1200	750/12	750	4710	1200	4000
	1000 TP 860	1000/8.6	1000	6280	860	2800

Models are designated by two numbers. The first one is an approximation of the capacity in m^3/d at 500 rpm and zero head, the second one indicates the nominal head capability in meters.
Series are designated by the size of the API stator thread

"Progressives" or "progressing" cavity pumps (cont.)

- **Performance curve:**



"Progressives" or "progressing" cavity pumps (cont.)

- **FIELD OF APPLICATION:**
  - Flow rate (at 500 RPM):
    - 0 / 3800 bpd (0 / 600 m^3/d)
  - Delivery head:
    - 0 / 5500 ft (0 / 1650 m)
  - Corresponding pump diameter and tubings:
    - Pump: 2.87 " 3.70 " 4.25 " 4.72 "
    - Tubing: 2 3/8 " 2 7/8 " 3 1/2 " 4 "
  - Maximum temperature:
    - 100 / 120 °C
  - Weak point: stator elastomer
  - Recommanded for viscous or sand-laden oil

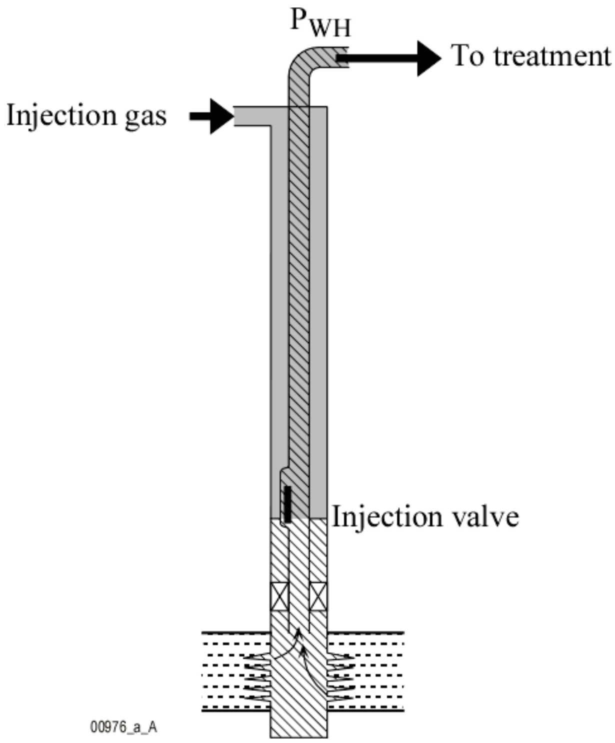
Gas lift

Gas lift

- Principle & Types of gas lift
- Well considerations in continuous gas lift
- Surface equipment for a gas lifted well

Gas lift principle

- **Gas injection into the tubing:**
  - At its "base"
  - Through the casing-tubing annulus
- **To aerate the formation fluid**

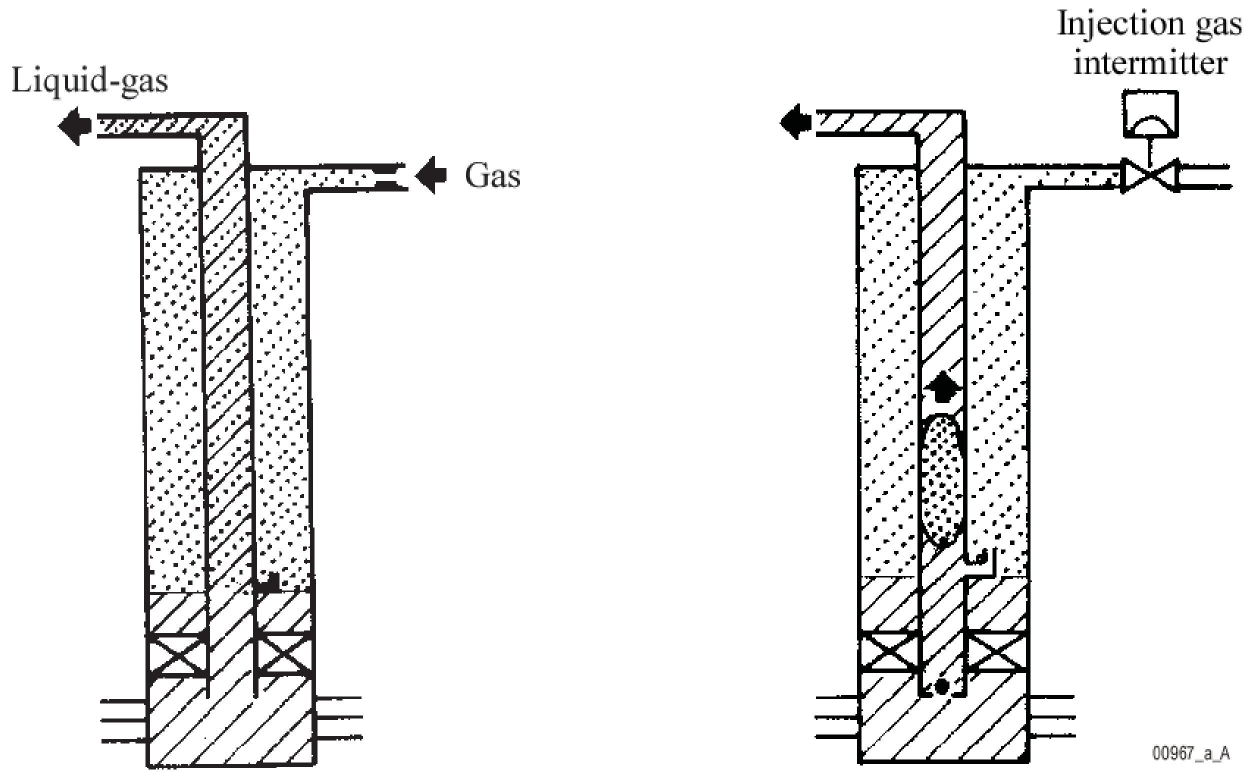


Gas lift principle

Types of gas lift

- **According to injection method:**
  - Continuous gas lift*
  - Intermittent gas lift*
- **According to surface injection circuit:**
  - Closed circuit*
  - Open circuit
- **According to the type of completion:**
  - Single or multi-zone completion*
  - Concentric completion*
  - Self gas lift*

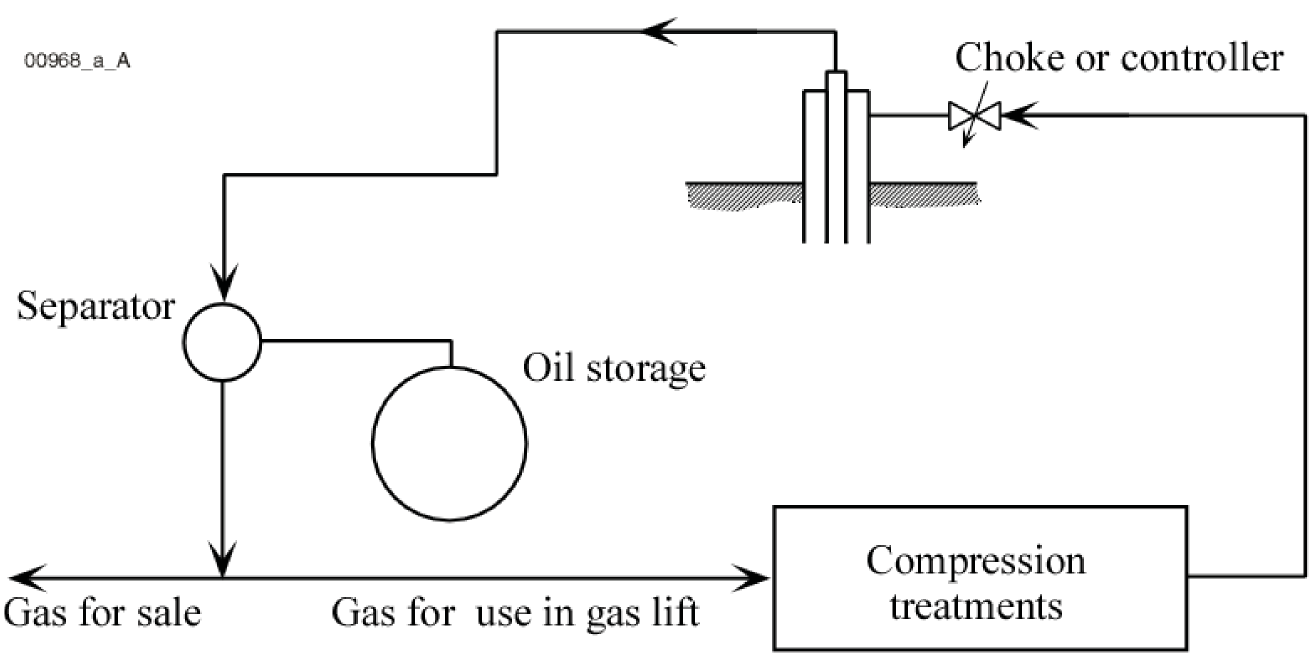
Continuous gas lift & Intermittent gas lift



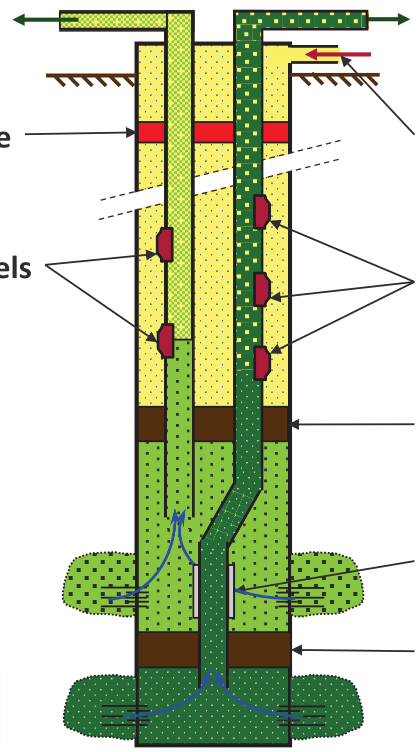
Continuous gas lift

Intermittent gas lift

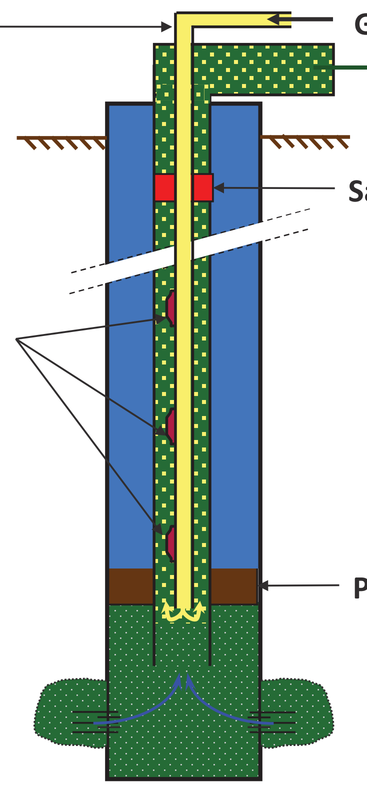
Surface facilities for a closed circuit gas lift



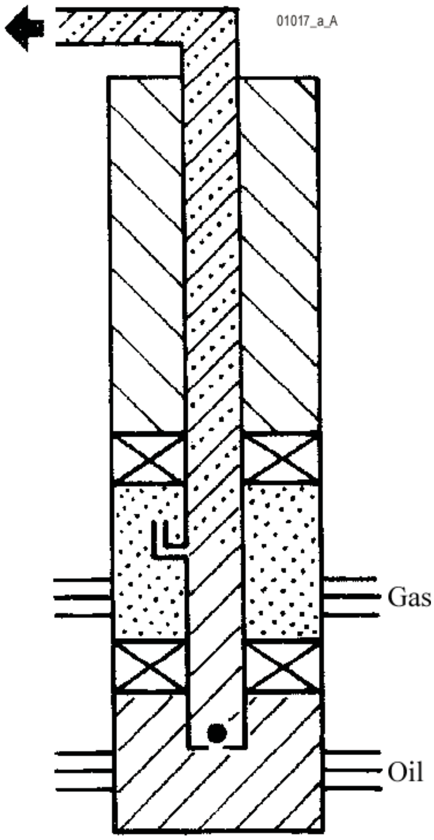
Gas lift in dual completion



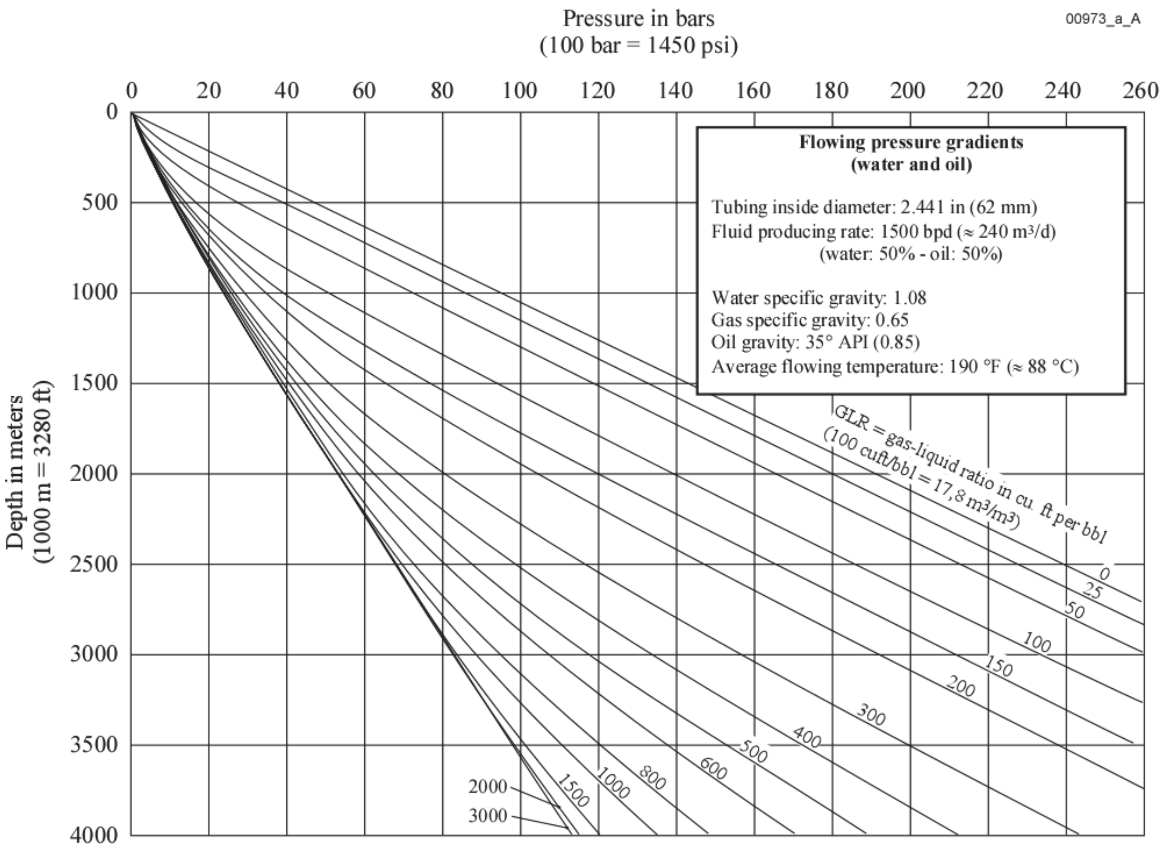
Concentric gas-lift



Self gas lift



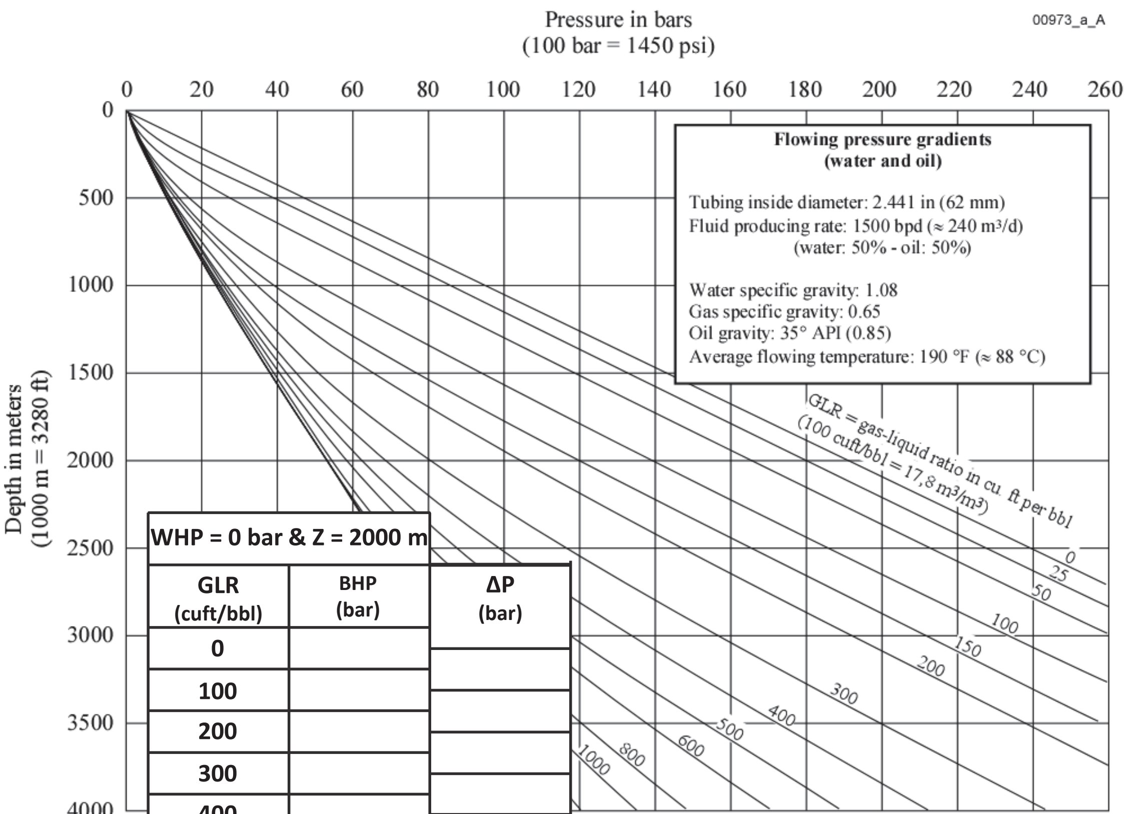
Pressure gradients in producing wells



Operating conditions

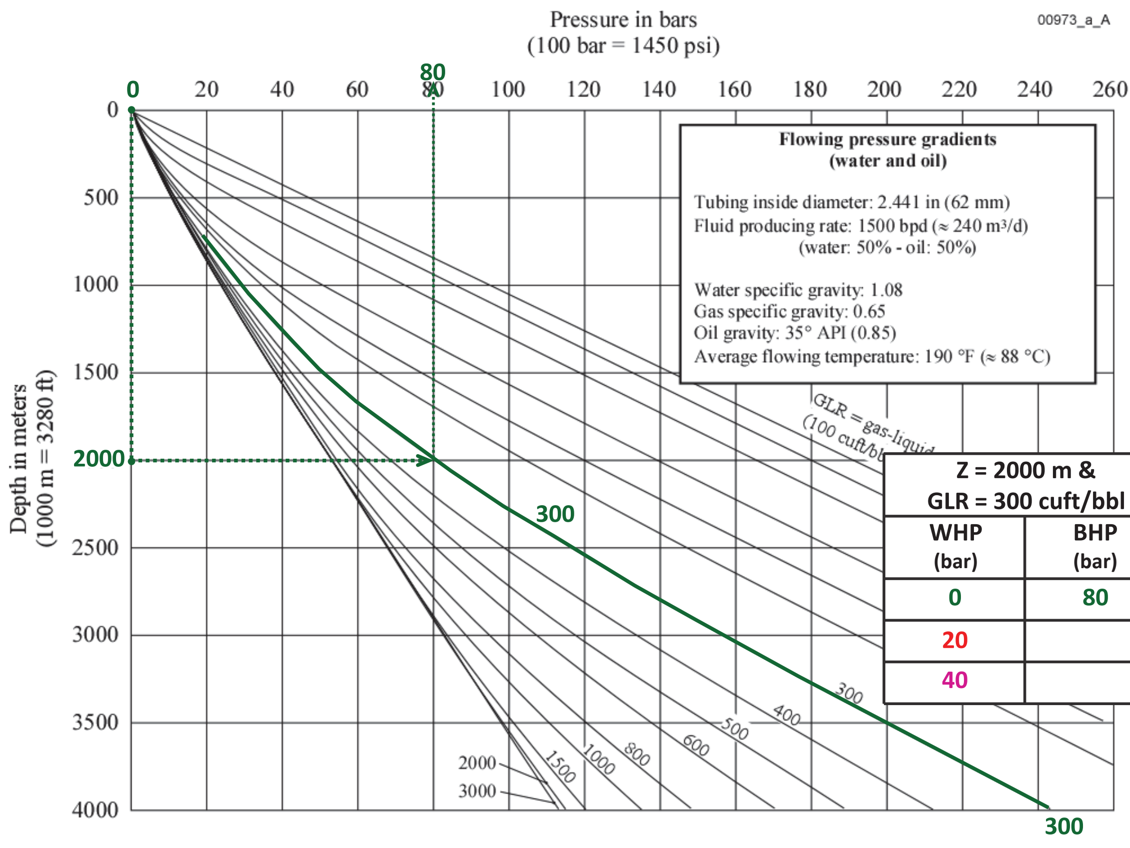
- **Injection parameters and optimisation *:**
  - Injection flow rate
  - Injection depth
  - Injection pressure
- **injection depth optimisation with time, in relation with the reservoir depletion***

Flowing pressure gradients: effect of GLR increase



WHP = 0 bar & Z = 2000 m		
GLR (cuft/bbl)	BHP (bar)	ΔP (bar)
0		
100		
200		
300		
400		

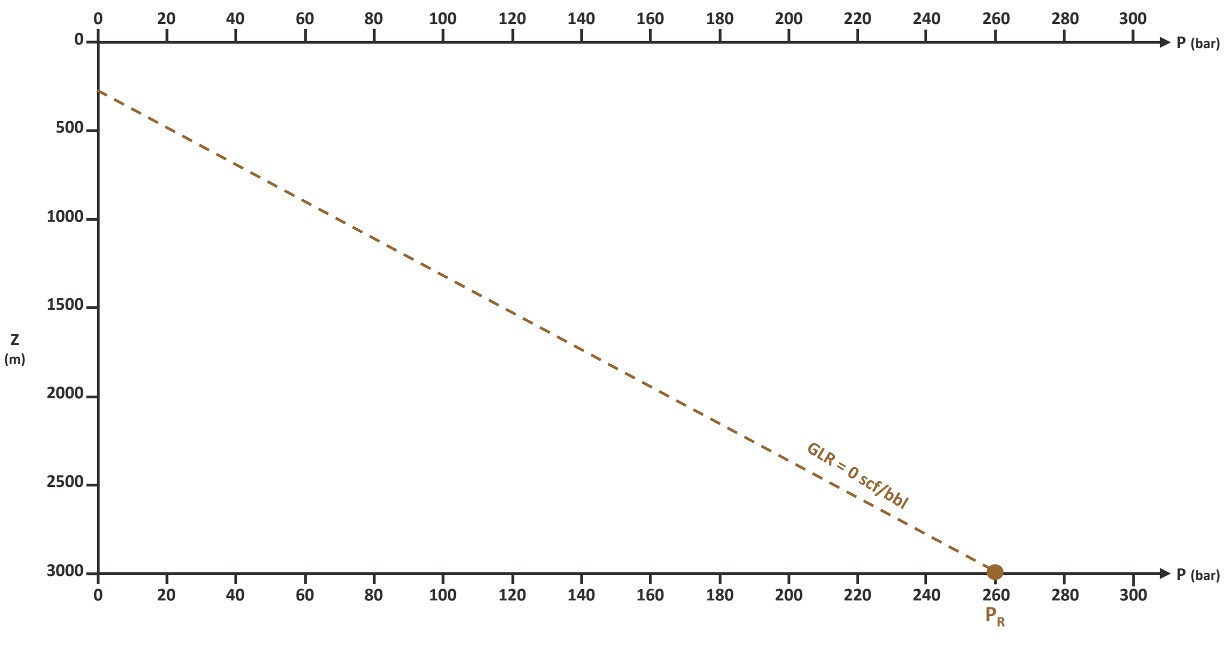
Flowing pressure gradients: effect of WHP increase



Z = 2000 m & GLR = 300 cuft/bbl		
WHP (bar)	BHP (bar)	ΔP_{BH} (bar)
0	80	
20		
40		

Determination of operating parameters (continuous gas-lift)

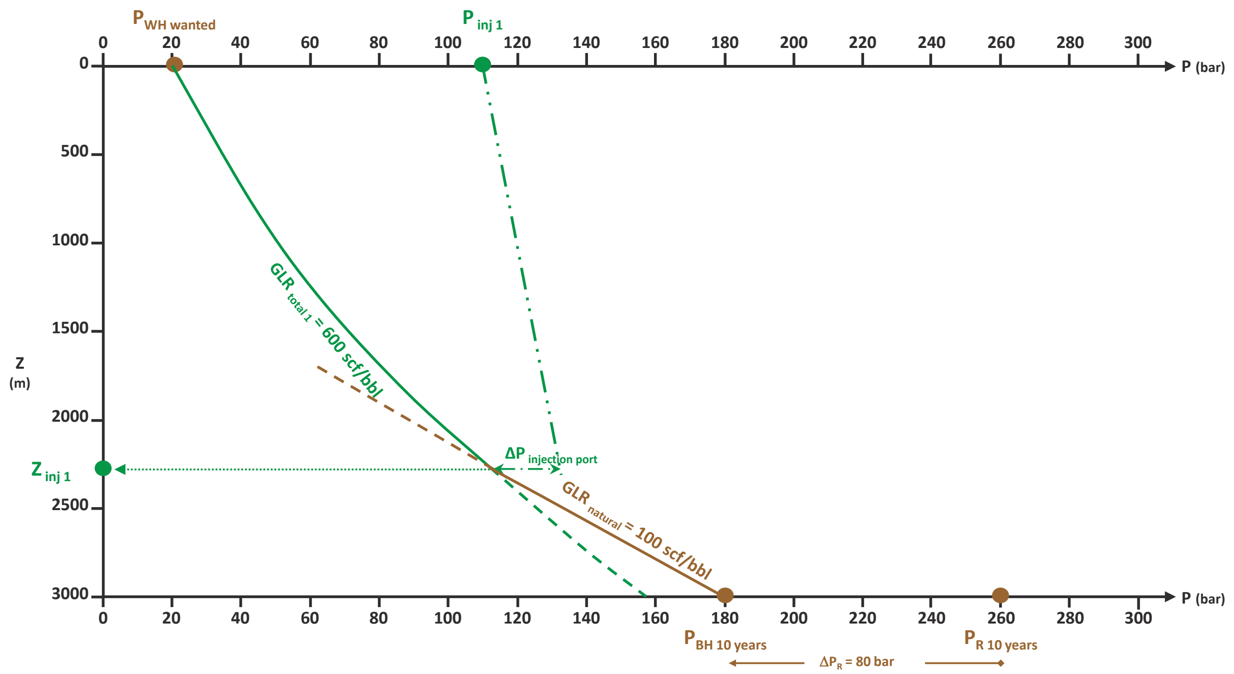
P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d with P_{WH} = 20 bar



Injection optimisation with time in relation with the reservoir depletion

WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d ⇒ $\Delta P_R = Q_L / PI_L$ = 240/3 = 80 bar, $P_{WH\ wanted}$ = 20 bar

The design has been done for $P_{R\ \text{"in10 years"}}$ = 260 bar, how to produce the same flow rate in only 5 years with $P_{R\ \text{"in 5 years"}}$ = 280 bar?



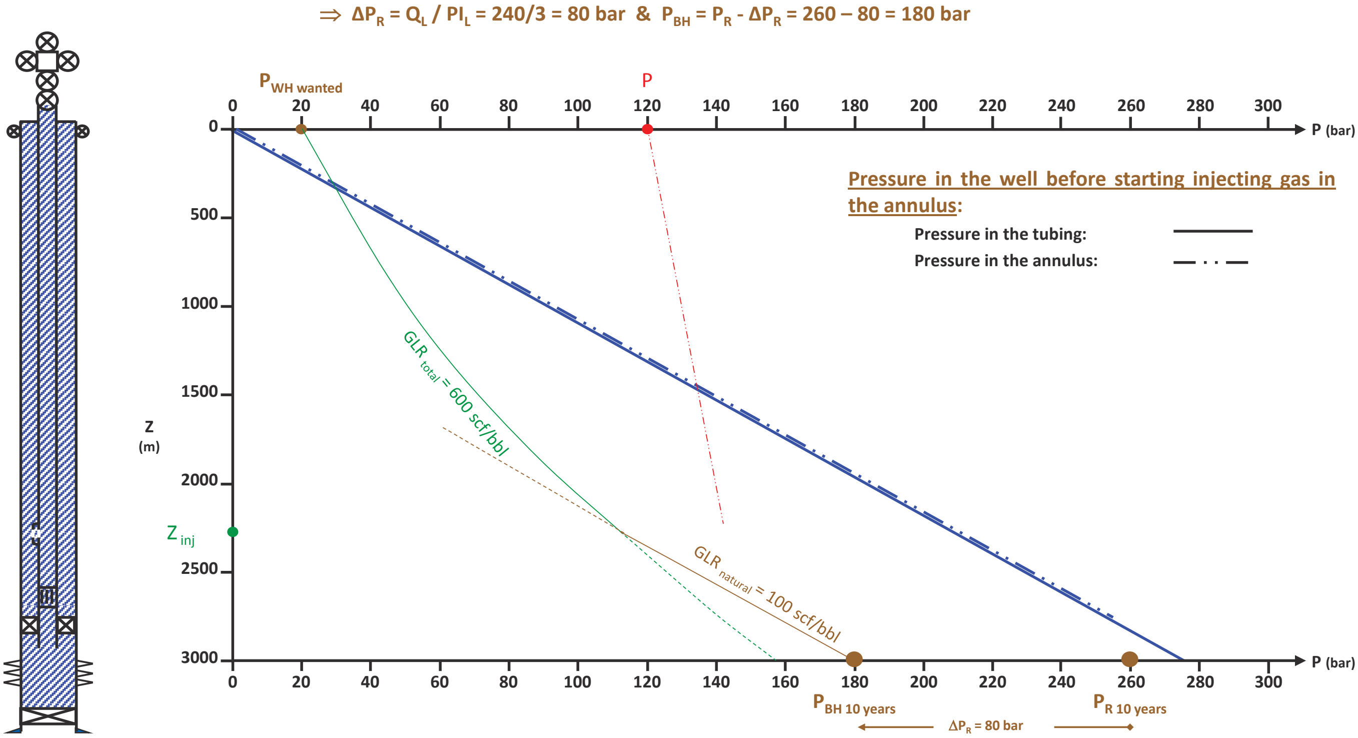
Unloading the well at start up

- Need for unloading valves
  & positioning the unloading valves*
- Synthesis: Unloading sequence*

Unloading the well (after a workover) (1/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\,wanted}$ = 240 m³/d with P_{WH} = 20 bar

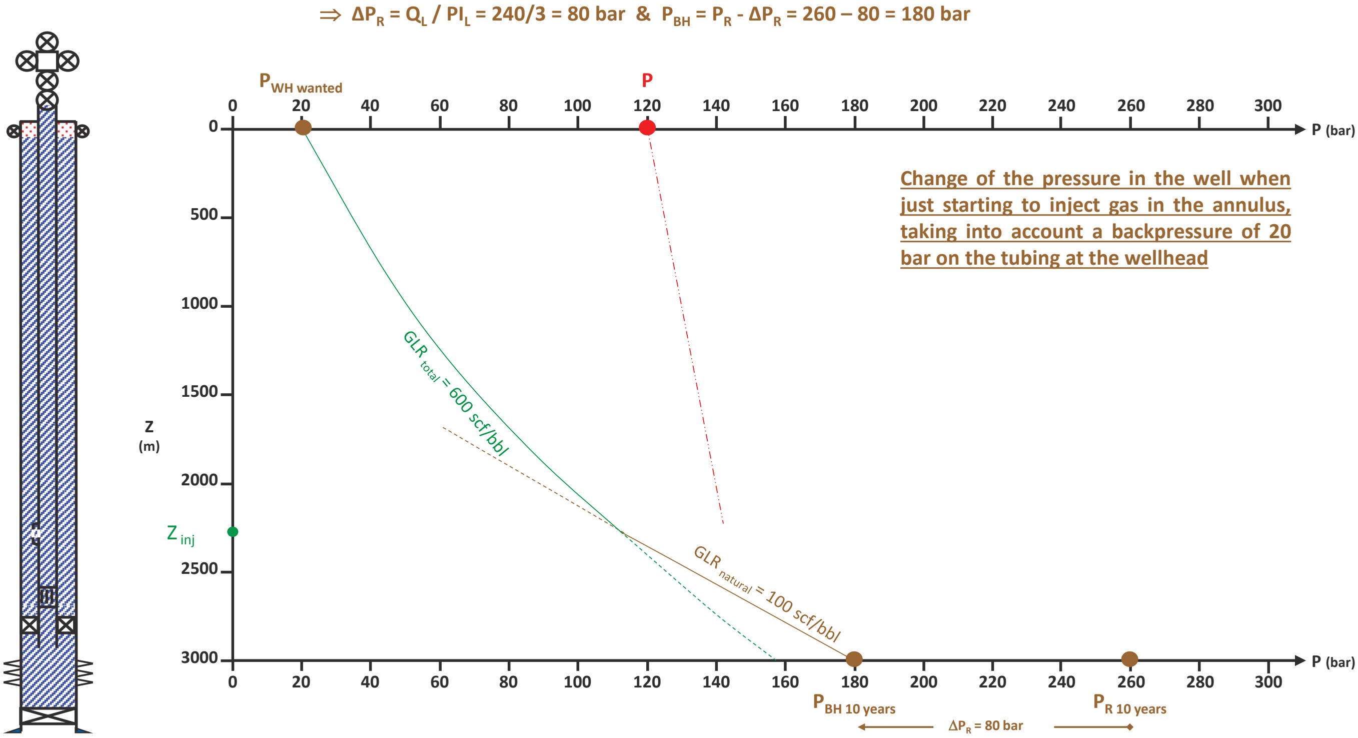
$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar



Unloading the well (after a workover) (2/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\,wanted}$ = 240 m³/d with P_{WH} = 20 bar

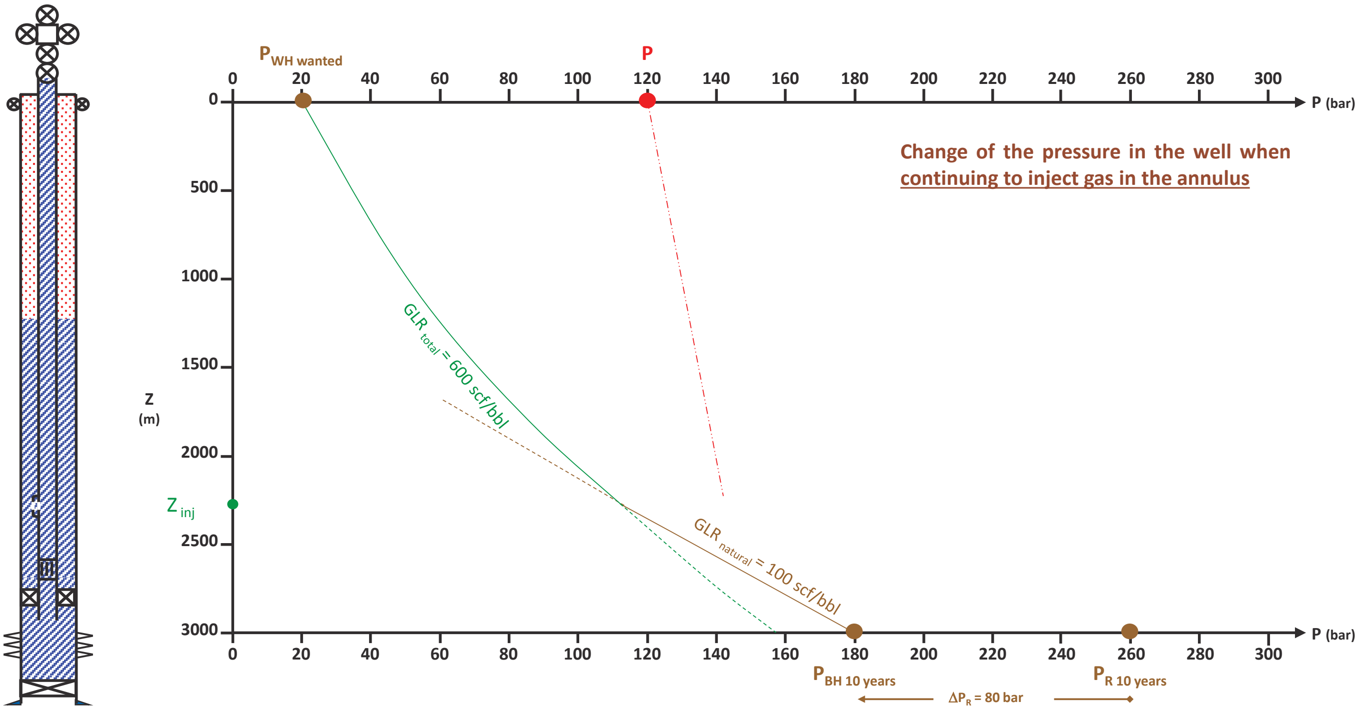
$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar



Unloading the well (after a workover) (3/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d with P_{WH} = 20 bar

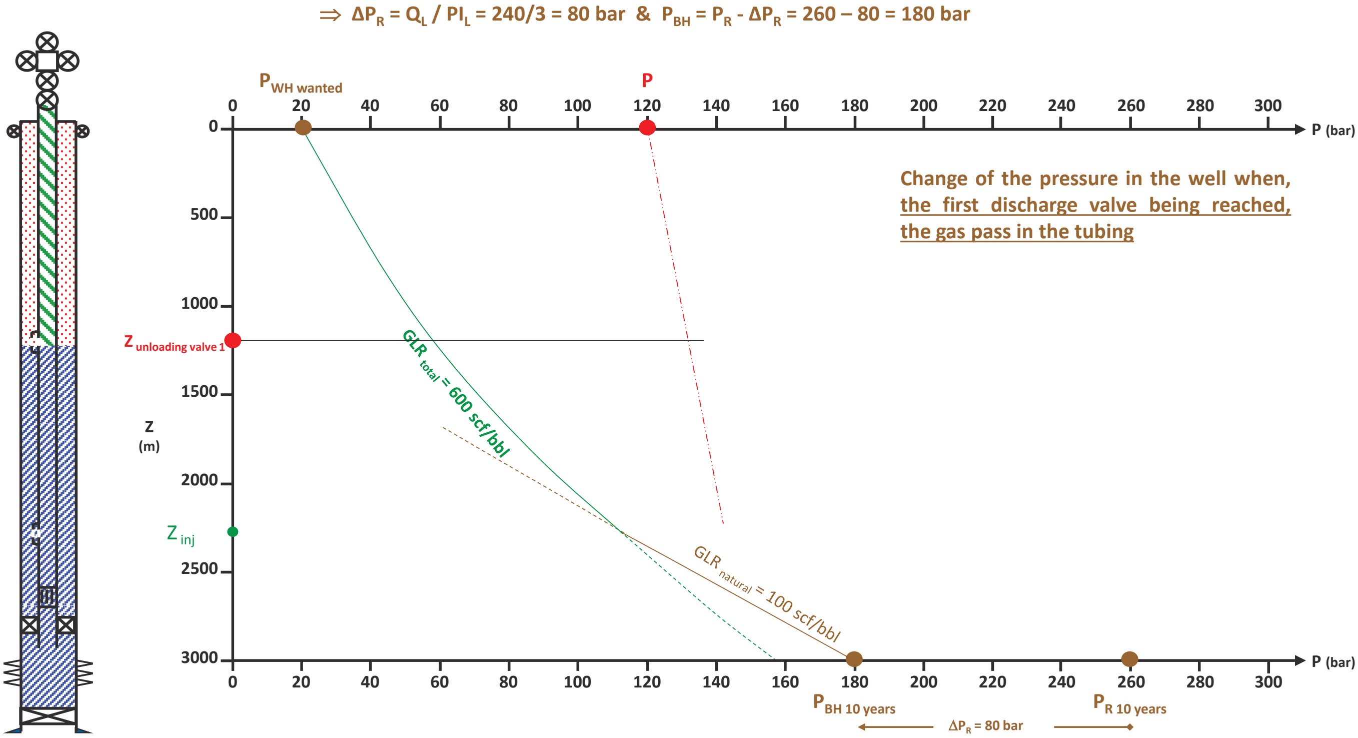
$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar



Unloading the well (after a workover) (4/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d with P_{WH} = 20 bar

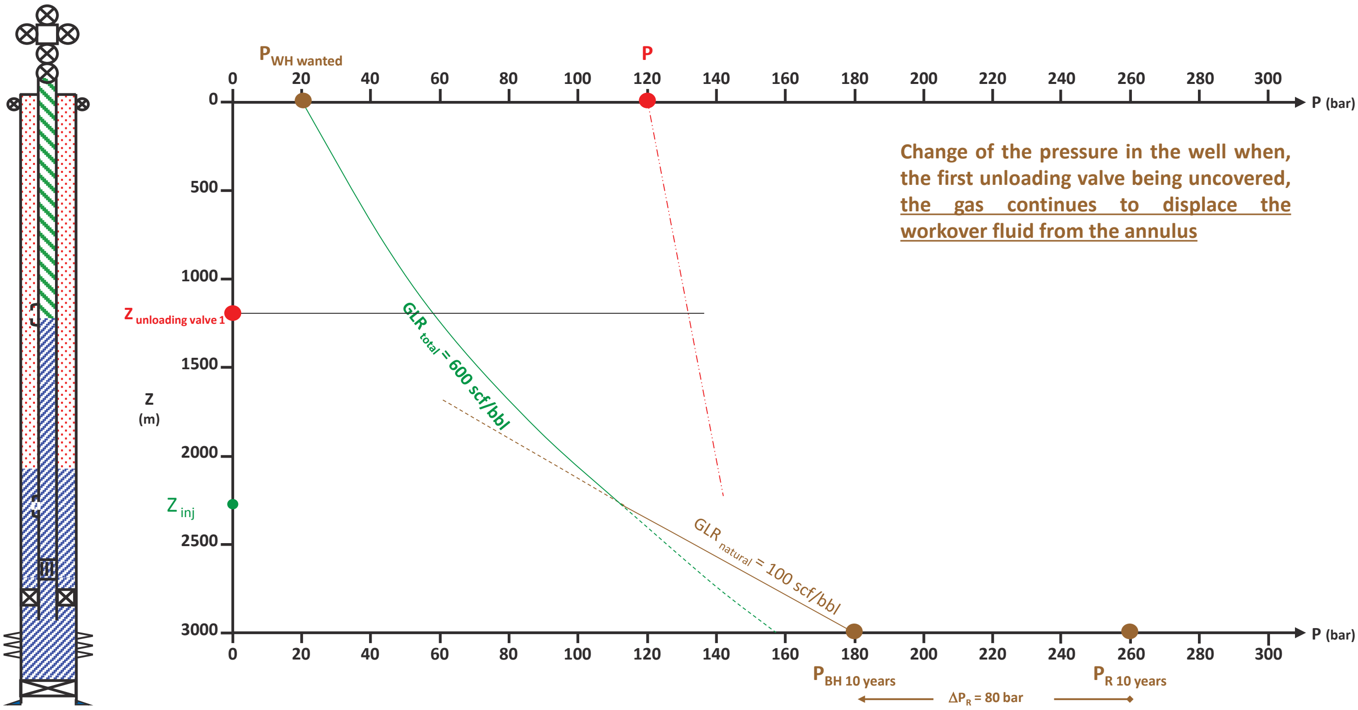
$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar



Unloading the well (after a workover) (5/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\,wanted}$ = 240 m³/d with P_{WH} = 20 bar

$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar

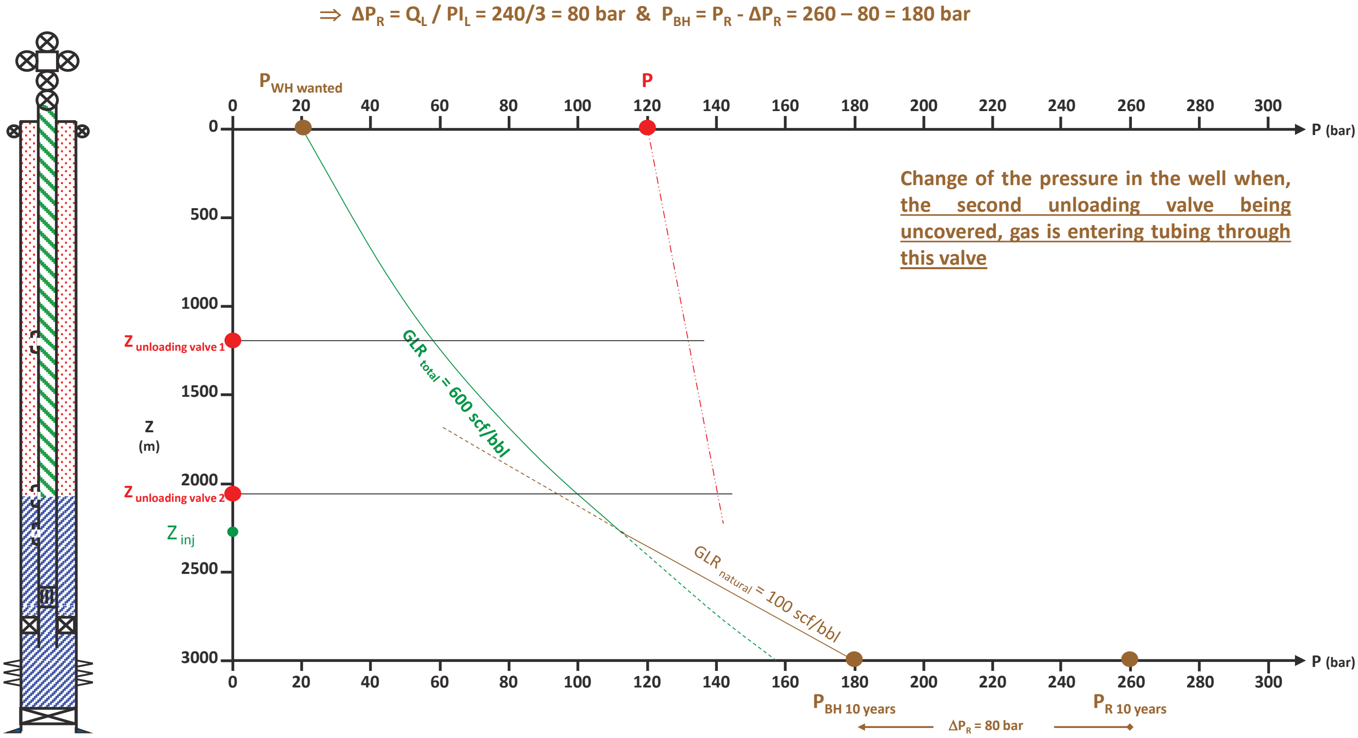


Change of the pressure in the well when, the first unloading valve being uncovered, the gas continues to displace the workover fluid from the annulus

Unloading the well (after a workover) (6/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\,wanted}$ = 240 m³/d with P_{WH} = 20 bar

$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar

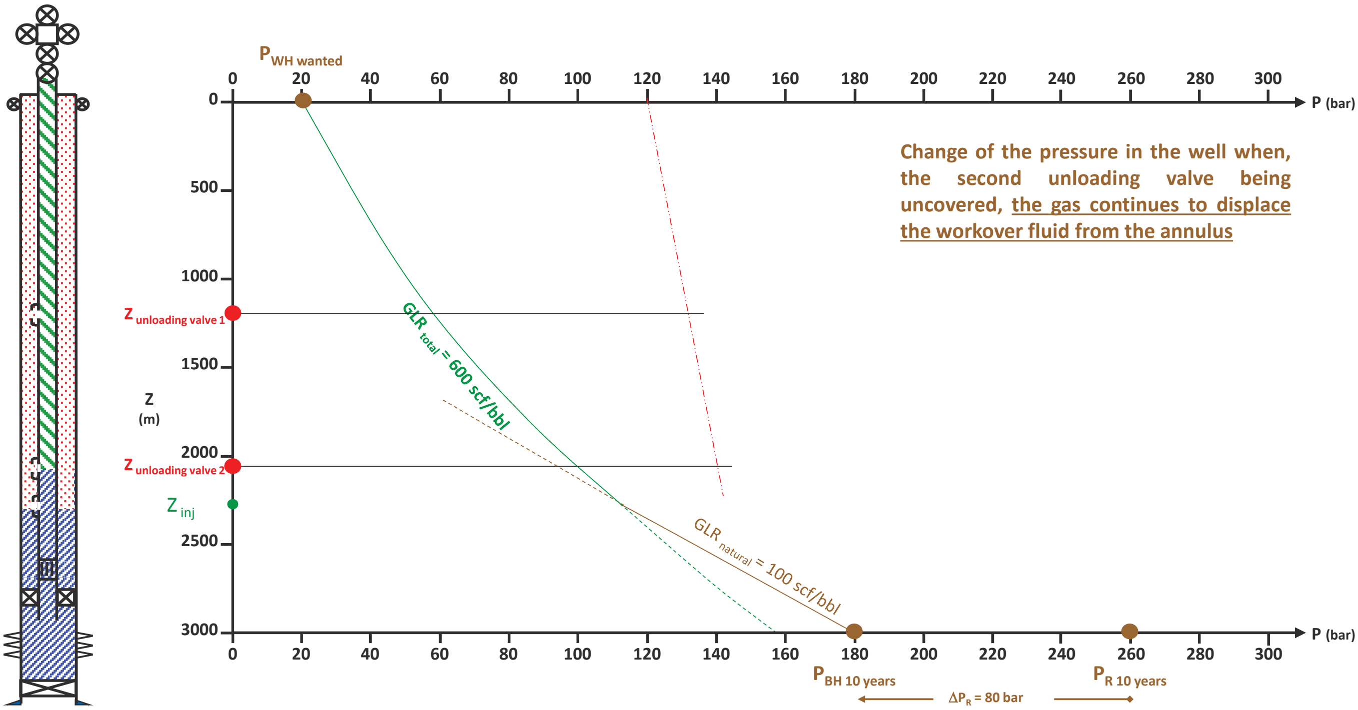


Change of the pressure in the well when, the second unloading valve being uncovered, gas is entering tubing through this valve

Unloading the well (after a workover) (7/8)

P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d with P_{WH} = 20 bar

$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar

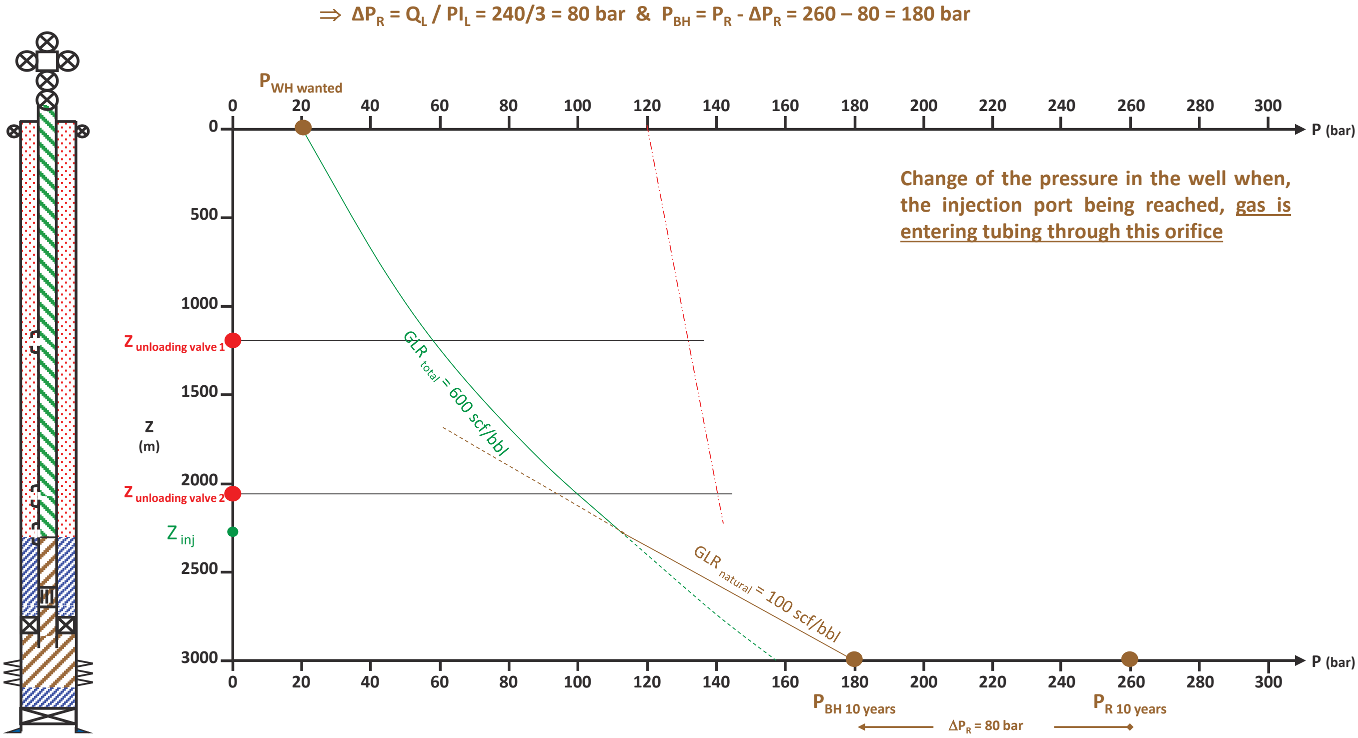


Change of the pressure in the well when, the second unloading valve being uncovered, <u>the gas continues to displace the workover fluid from the annulus</u>

Unloading the well (after a workover) (8/8)

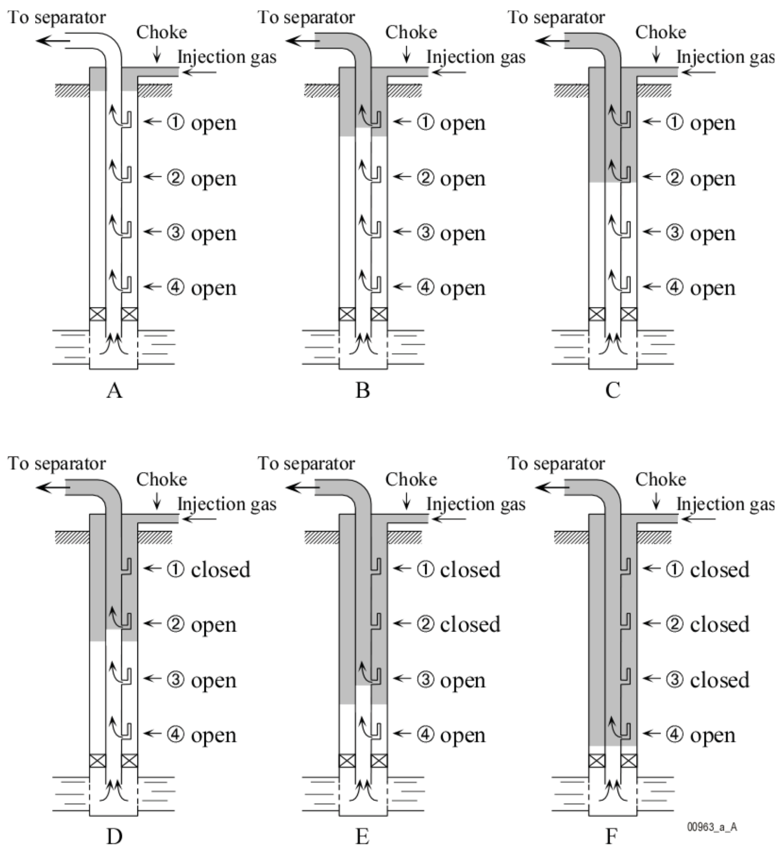
P_R = 260 bar, WOR = 1, $GLR_{natural}$ = 100 scf/bbl, PI_L = 3 m³/d/bar, $Q_{L\ wanted}$ = 240 m³/d with P_{WH} = 20 bar

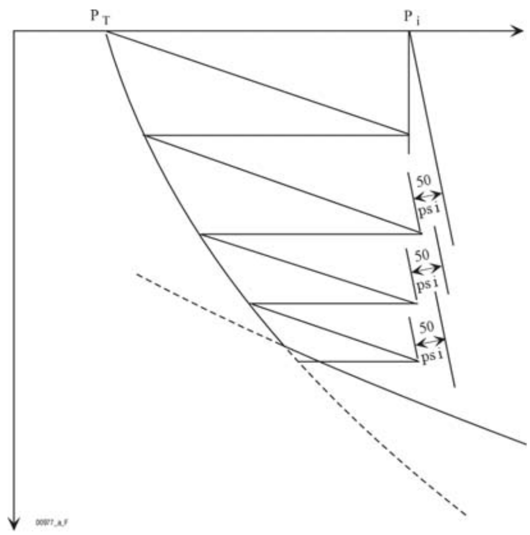
$\Rightarrow \Delta P_R = Q_L / PI_L = 240/3 = 80$ bar & $P_{BH} = P_R - \Delta P_R = 260 - 80 = 180$ bar



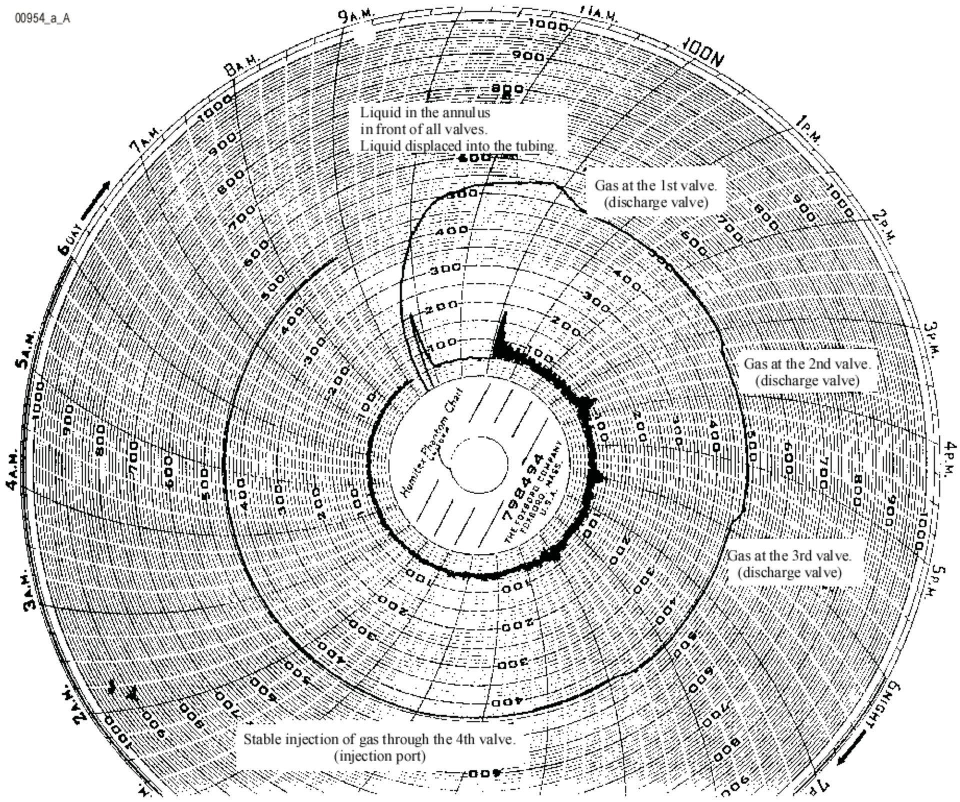
Change of the pressure in the well when, the injection port being reached, <u>gas is entering tubing through this orifice</u>

Unloading the well at start up (continuous gas lift)





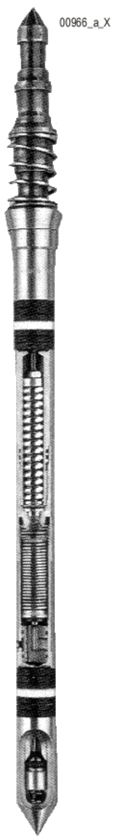
Tubing & casing pressure recording (during gas-lift unloading)



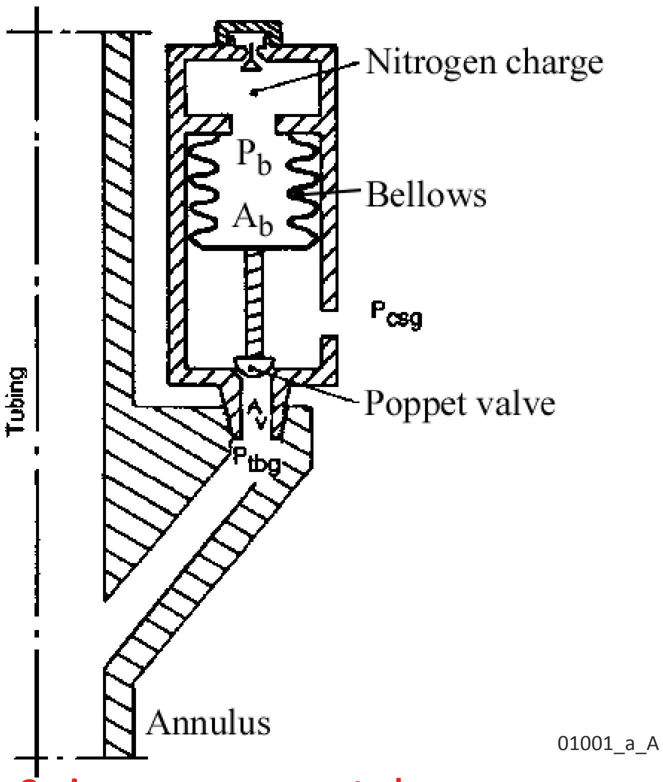
Gas-lift valve technology

- Principle*
- Casing pressure operated valve*
- Tubing pressure operated valve*

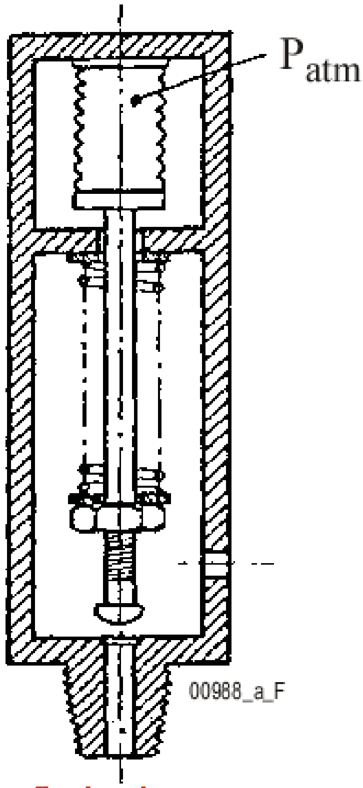
Gas-lift valve



"Casing operated" gas-lift valve

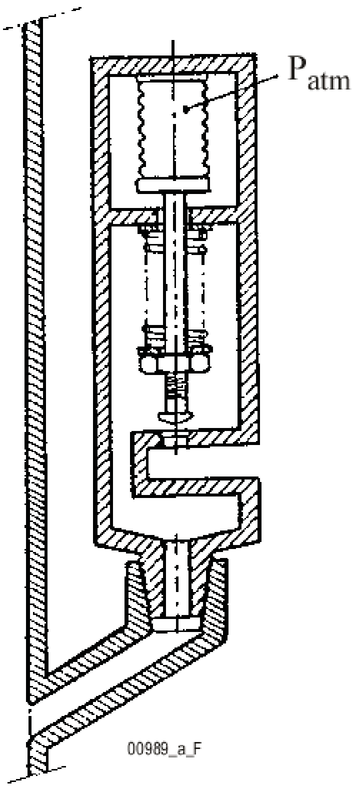


Casing pressure operated gas-lift valve



Spring type casing operated valve

"Tubing pressure operated" gas-lift valve

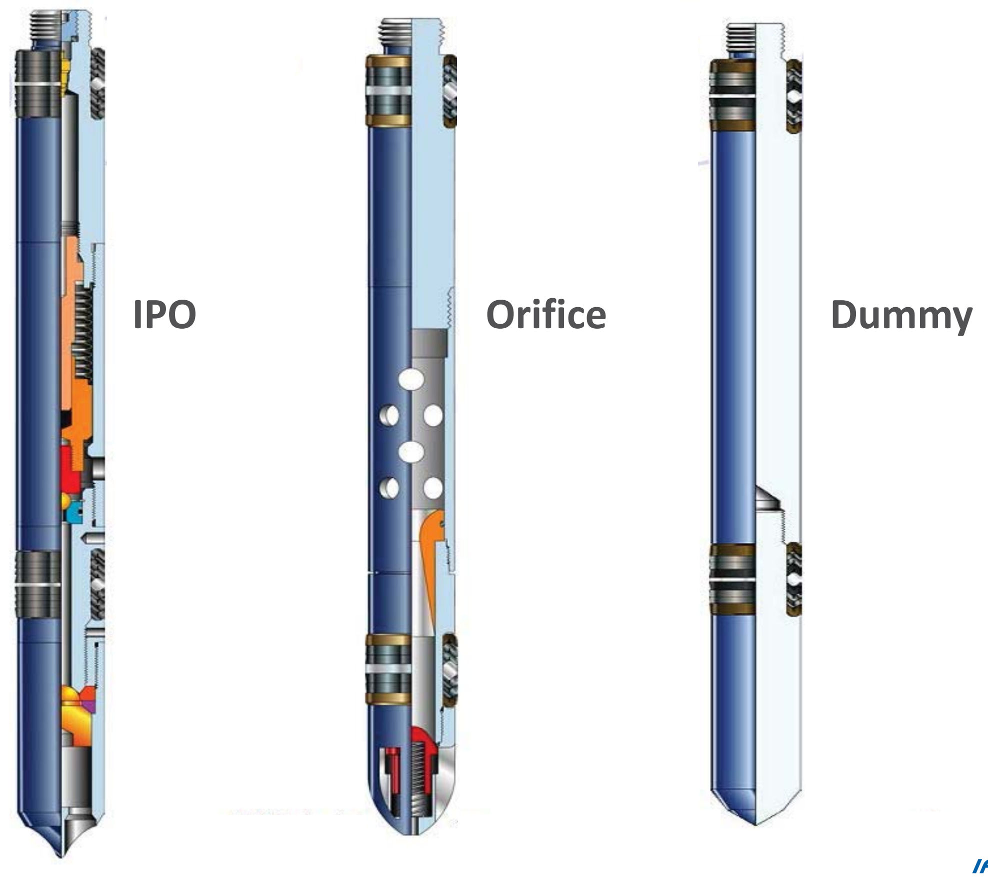


Gas-lift valves naming convention

Function	Kick-off / Unloading		Continuous Injection	Mandrel sealing
Type	Operated by injected gas pressure	*Operated by tubing pressure*	Simple orifice	Plug
Name	P Pressure operated *or* casing operated (IPO = Injection Pressure Operated)	*F* *Fluid operated* *or* *tubing operated* *(PPO = Production Pressure operated*	O or DKO	D or Dummy

Suppliers coding		
MACCO	CM1-BK	DKO
CAMCO	BK ou BK1	DKO2

Wireline Retrievable Gas-Lift Valves



Gas Lift valves function

- **Unloading valve:**
  - Is used to temporarily allow gas injection into the tubing at an intermediate depth during unloading
    - Opens when pressure exceeds opening pressure
    - Gas rate through the valve, when open, is limited by a port
    - Valve must close after gas uncovers next valve

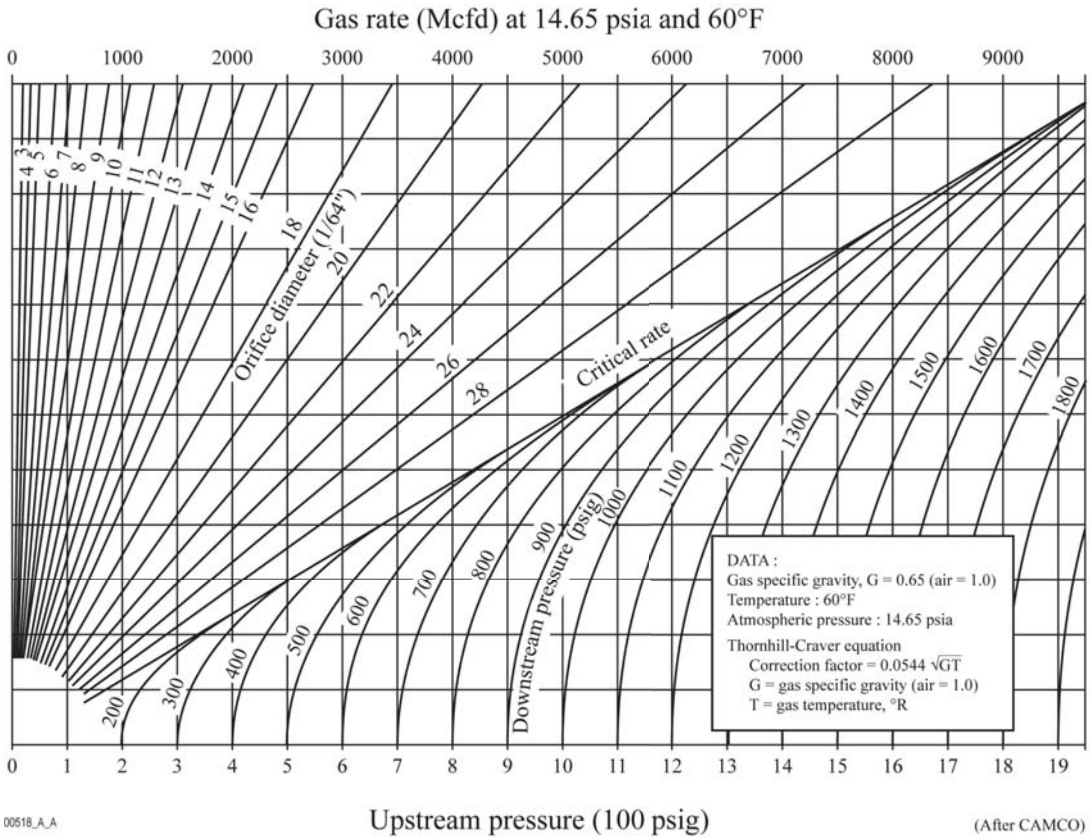
Gas Lift valves function (cont.)

- **Operating valve:**
  - Injects gas at final injection depth during normal operations, stays permanently opened
    - Usually a simple orifice on high productivity wells (PI > 0.5 bpd/psi): controls gas injection rate while avoiding valve throttling and allowing a larger rate span
    - On low productivity wells, resorting to a P type gas lift valve is advisable
- **Dummy:**
  - Is a solid plug to seal mandrel and protect its polished bore

Gas lift valve port selection

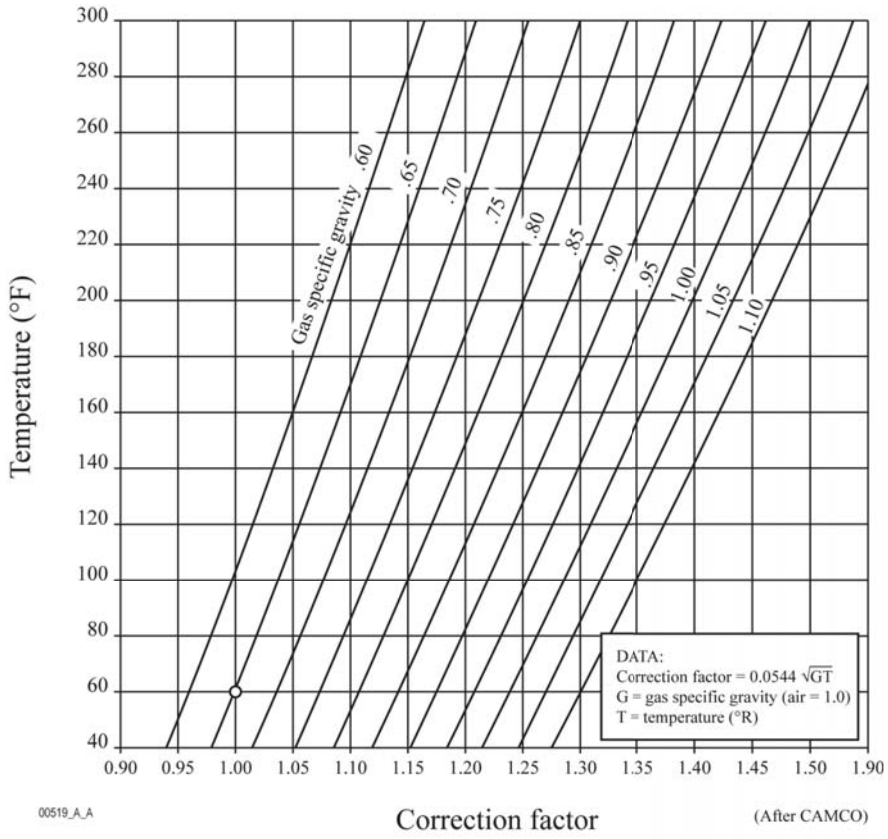
- **Function: Gas injection rate limitation**
- **Charts allow to determine the required port size depending on*:**
  - Required gas rate (after correction, see here below)
  - Upstream pressure = casing pressure at depth
  - Downstream pressure = tubing pressure at depth
- **Gas rate, expressed in standard volumes, must be corrected for*:**
  - The actual gas specific gravity (chart done for SG = 0.65)
  - The actual temperature at valve depth
- **Such port will allow for some gas rate flexibility***

Gas rate through different orifice diameter

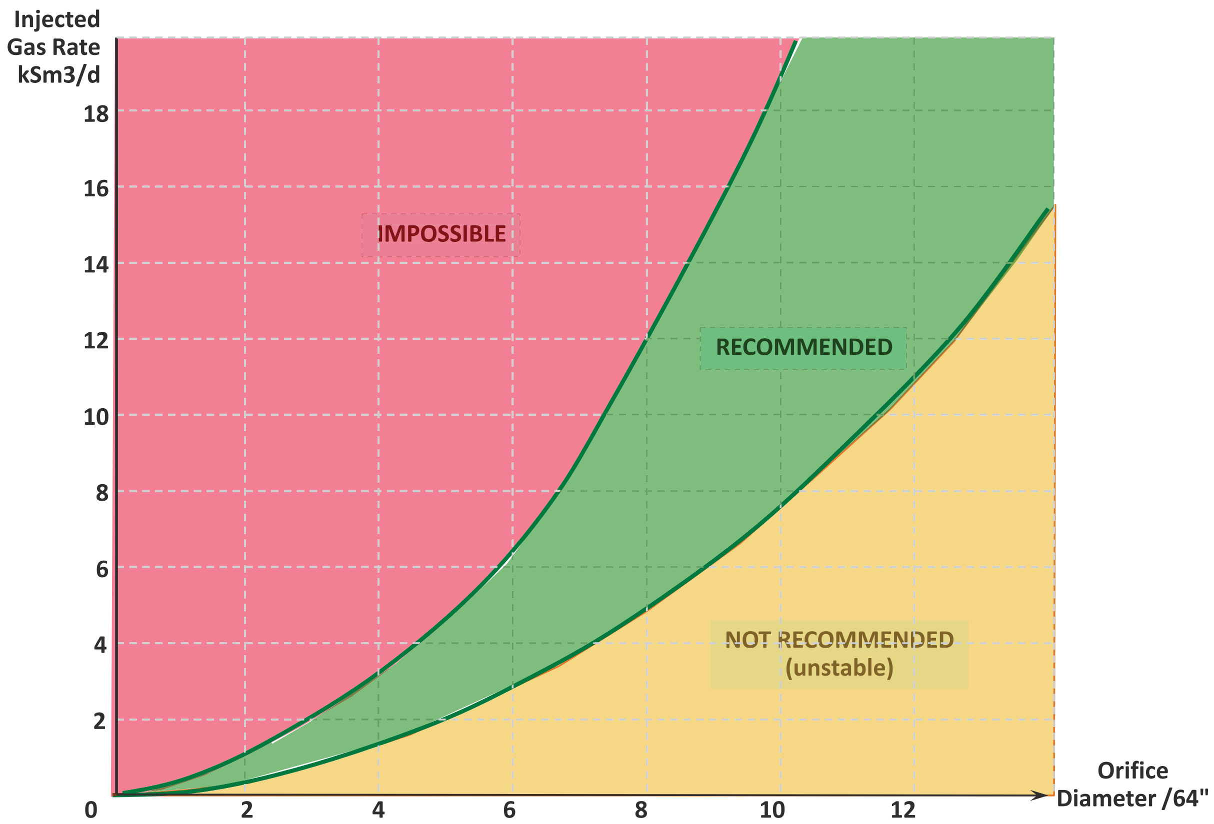


(After CAMCO)

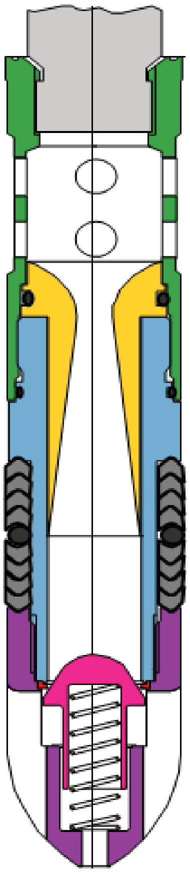
Correction factor for gas flow capacities chart



Gas rate span of gas-lift valves at 80 bar – 1 200 psi

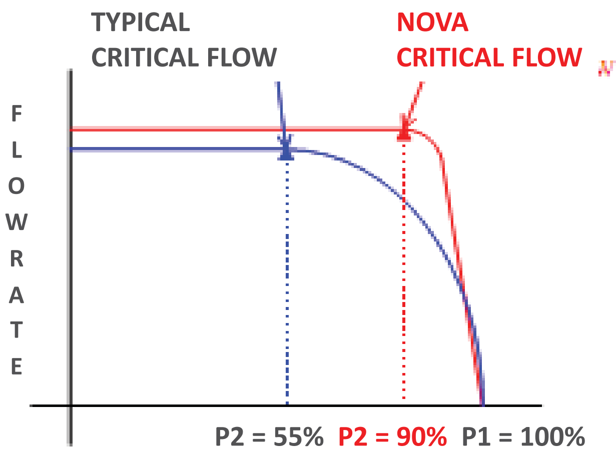


NOVA Orifice Gas-Lift Valve



NOVA™ Technical Specifications

- NACE approved Stainless Steel material construction.
- Industry Standard 1" and 1-1/2" valve formats.
- Compatible with existing side-pocket mandrels, latches and slickline tools.
- Compatible with existing unloading valves.
- Erosion resistant material options.



P1 = UPSTREAM PRESSURE
P2 = DOWNSTREAM PRESSURE

Opening pressure and closing pressure of a gas lift valve

- **Forces balance at valve opening:**
  - A_b = bellows area, nitrogen pressured to P_b
  - A_s = seat area, subject to P_{tubing}
  - $A_b - A_s$ = area subject to P_{casing}

$P_b \times A_b = P_{csgo} \times (A_b - A_s) + P_{tbg} \times A_s$

$P_{csgo} \times (A_b - A_s) = P_b \times A_b - P_{tbg} \times A_s$

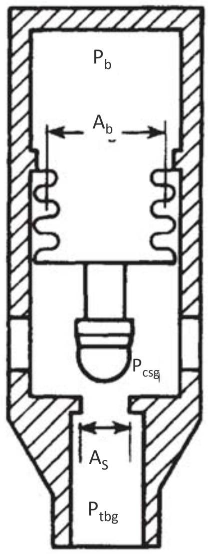
$P_{csgo} \times (1 - As/A_b) = P_b \times 1 - P_{tbg} \times A_s/A_b$

A_s/A_b = valve characteristic provided by manufacturer

$P_{csgo} = [P_b - P_{tbg} \times (A_s/A_b)] / [1 - (A_s/A_b)]$

- **Forces balance at valve closing:**
  - Just before closing, P_{csgc} applies on $(A_b - A_s)$ as above and also on sea

$P_{csgc} = P_b$

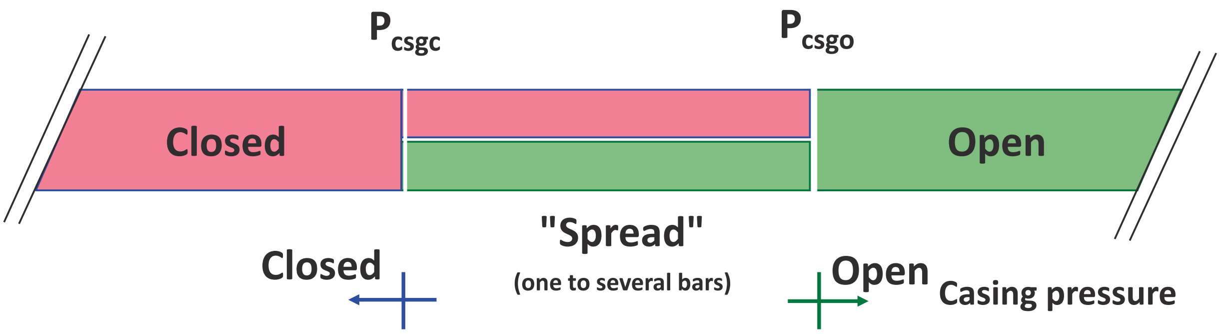


Gas Lift valve spread

Casing operated gas lift valve spread:
difference between "Opening" and "Closing" pressure

Casing pressure **increases** ➡ Valve **opens**

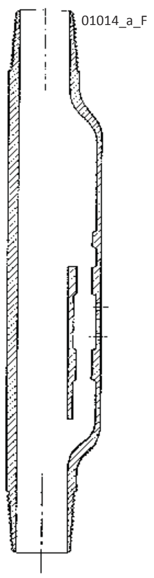
Valve **closes** ⬅ Casing pressure **decreases**

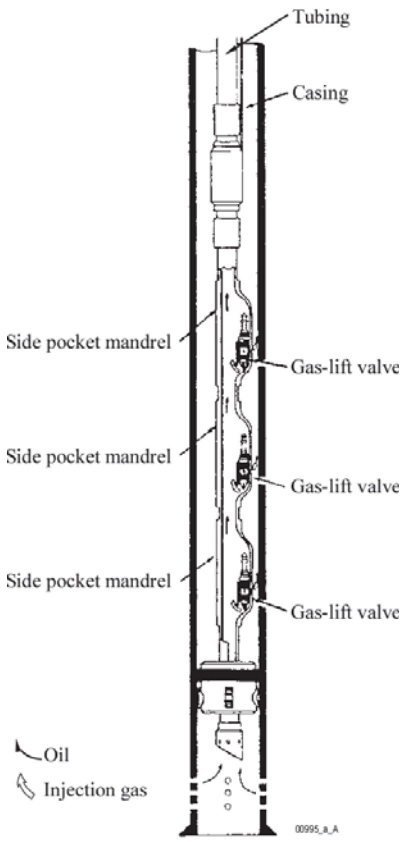


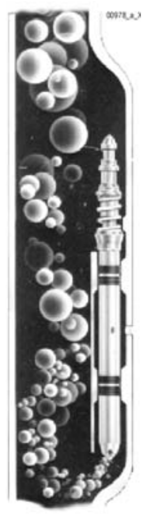
Tubing equipment specific to gas lift

- **Valve mandrel :**
  - Conventional mandrel*
  - Side pocket mandrel*
    & kickover ou positioning tool*
  - Mandrels with concentric valves *
- **Check valve**
- **Annulus safety valve* :**
  - together with a tubing safety valve
- **Tubing-head spool***

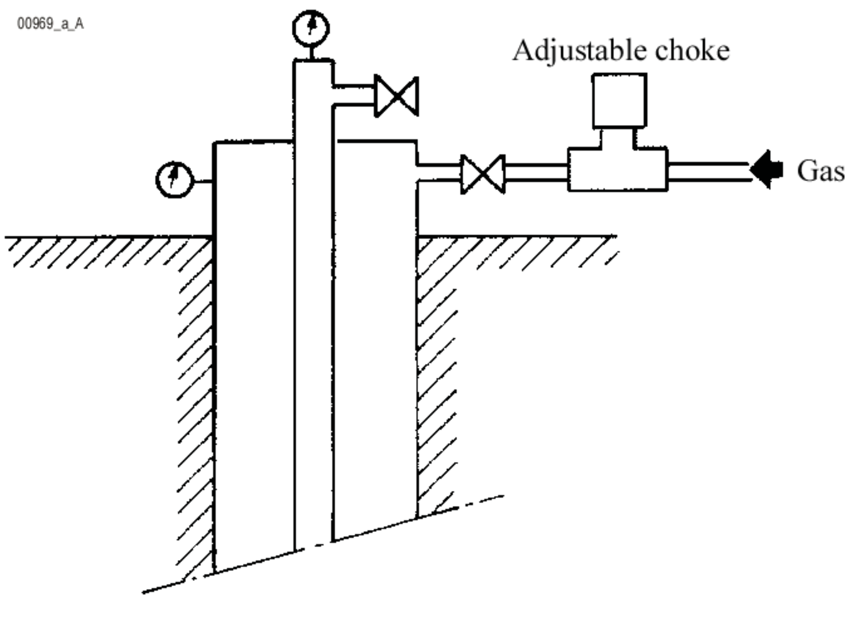
Side pocket mandrel

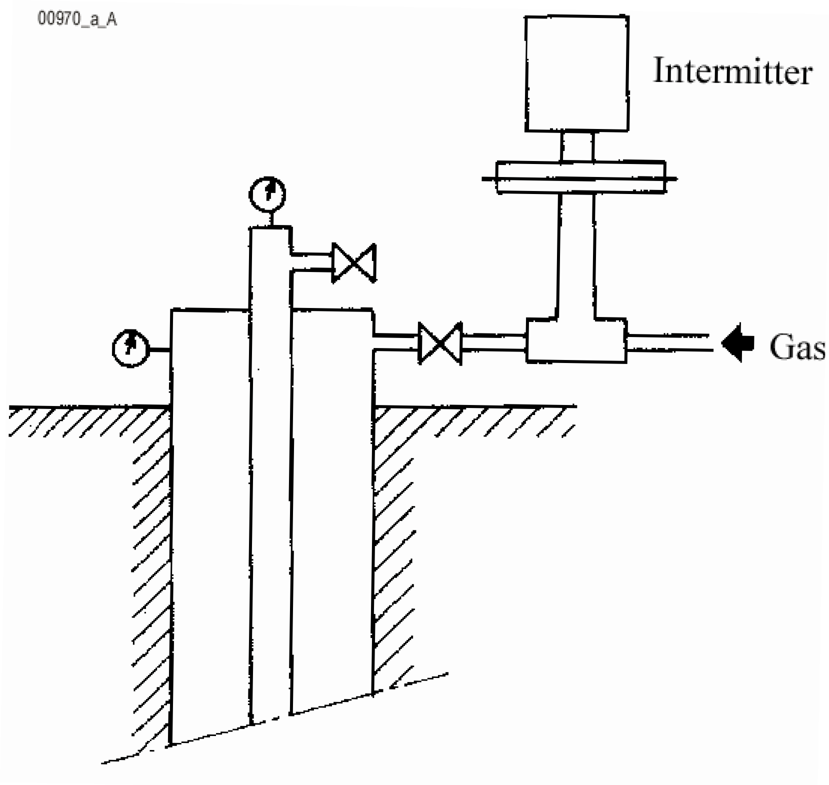




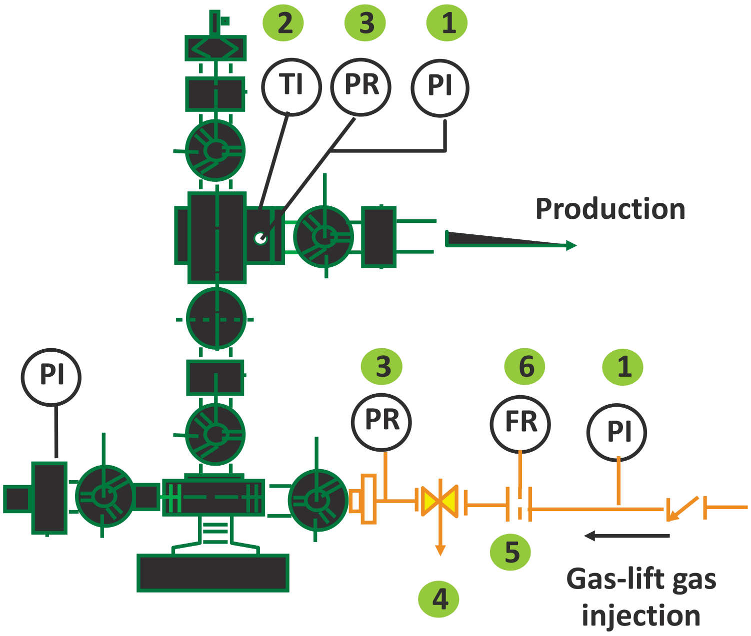


Wellhead equipment for continuous gas lift





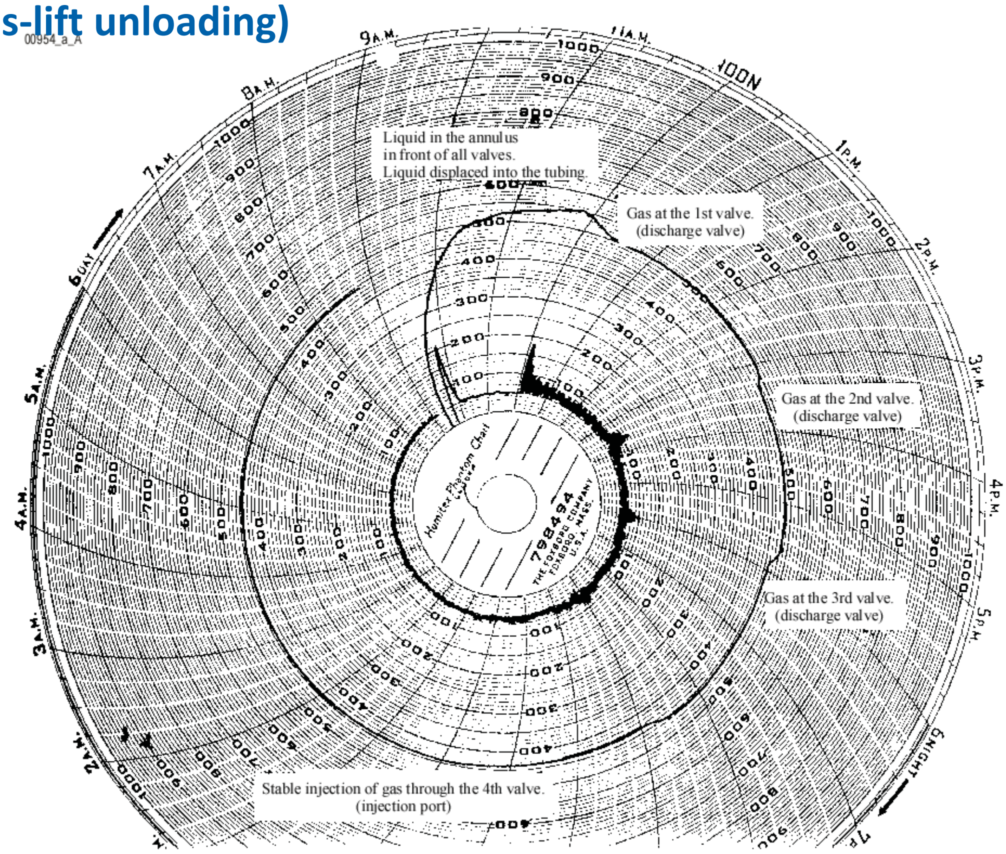
Gas lift well surface indicators & recorders (manual operations)



Symbols:

1. PI: Pressure Indicator
2. TI: Temperature Indicator
3. PR: Pressure Recorder (Casing and Tubing pressures)
4. Manual gas injection choke
5. Orifice flowmeter
6. FR: Flow Recorder

Tubing & casing pressure recording (during gas-lift unloading)



Choosing an artificial lift process

Choosing an artificial lift process

- Economic criteria, technical criteria & making a decision

Economic criteria

- **The problem is to recover the oil:**
  - The fastest
  - In the largest amount
  - At the lowest cost
- **Initial investment cost:**
  - Specific cost
  - Extra cost due to artificial lift problem
- **Operating and maintenance cost:**
  - Specific cost
  - Extra cost due to artificial lift problem
- **Example***

Cost of artificial lift: example

- **Gas lift:**
  - Investment:
    - Well: SPM + valves — 4 to 30 k $
    - Platform: compression — 0 to 20 M $ per field
  - Exploitation:
    - HP gas — 0 to 0,1 $ per Sm^3 *[0 to 2.8 $ per k.scf]*
    - Wireline — 2 to 10 k $ per well & per year (on average)
    - Workover — 0
- **Electrical submersible pump:**
  - Investment:
    - Well: pump + cable — 60 to 160 k $ per well
    - Platform: electrical supply — 0 to 0.1 m $ per field
  - Exploitation:
    - Electrical power — 0 to 0.1 $ per kWh
    - Workover — 40 to 160 k $ per well & per year (on average)

Technical criteria

- **Energy:**
  - Availability
  - Access cost
- **Dynamic head and flow rate**
- **Other criteria:**
  - General environment
  - Surface infrastructure and immediate environment
  - Well architecture
  - Effluent characteristics

Making a decision

- **Based on criteria as:**
  - Qualitative and quantitative
  - Difficult to access, vary with time
- **Be careful not to be misled by previous experiences**
- **A temporary system can be selected:**

  ⇒ **be sure it does not become permanent without having been reassessed**

Choosing an artificial lift process

- Main advantages and drawbacks of artificial lift processes

Sucker rod pumping

- **Main advantages:**
  - The most widespread technology, relatively simple and well known in the industry
  - Well suited to low and moderate flow rates
  - The flow rate can be changed easily
  - Compatible with very low bottomhole pressure
  - Subsurface problem can be solved by a relatively lightweight servicing unit
  - Suited to isolated wells
  - Standard units are simple and durable:
    $\Rightarrow$ low operating expenses
  - Long stroke units very useful for viscous and gassy crudes

Sucker rod pumping (cont.)

- **Main drawbacks:**
  - Possible flow rate decreases severely with the depth required for the pump
  - Reduced volumetric efficiency in wells with high GOR
  - Standard units are too bulky and heavy for offshore platforms
  - Initial investment cost is high for large capacity pumps
  - Major problem of rod strength when there is a corrosive effluent
  - Ill suited to "crooked" well profiles

Electric submersible pumping

▶ **Main advantages:**

- High flow rates are possible at shallow or average depths
- Well suited to production with a high water cut
- Surface equipment takes up little space
- Daily monitoring problems reduced to a minimum
- Good energy efficiency

Electric submersible pumping (cont.)

▶ **Main drawbacks:**

- Output capacity strongly influenced by depth
- Limited in temperature and consequently in depth
- Ill suited to low flow rates
- Tubing must be pulled in the event of trouble:
  $\Rightarrow$ operating costs and downtime costly , especially offshore
- Not usually recommended when the GOR is high
- Performs poorly in the presence of sand
- Little flexibility

Hydraulic pumping

- **Main advantages:**
  - Suited to great depths and deviated wells
  - Pump (depending on the installation) can be pumped up to the surface
  - Driving fluid can serve as a carrier fluid for injecting an additive

And, for the plunger pump:

  - The size and rate of the pump can easily be modified to adapt to well conditions
  - Viscous heavy crudes benefit from being mixed with a lighter driving oil
  - Production is possible with extremely low bottomhole pressures

And, for the jet pump:

  - High production flow rate is possible
  - No moving part inside the well
  - Only minor problems if sand or gas are present

Hydraulic pumping (cont.)

- **Main drawbacks:**
  - Initial investment in surface equipment is quite high and its maintenance is fairly expensive
  - High pressure pump feed circuit (with consequent safety risks)
  - Well testing causes problems, especially regarding assessment of produced fluids
  - Completion with multiple tubings may be required

And, for the plunger pump:

  - Rapid wear and tear on the pump if the fluid is corrosive or abrasive
  - Efficiency drastically lowered if free gas is present

And, for the jet pump:

  - Low efficiency, 25 to 30 % (70 % for plunger pumps)
  - Need for bottomhole flowing pressure of over 3.5 MPa (500 psi), otherwise detrimental cavitation takes place in the flow nozzle
  - Is prone to form emulsions or foam

Continuous gas lift

▶ **Main advantages:**

- Well suited to average or high flow rates
- Suited to wells with a good PI and relatively high bottomhole pressure
- Well equipment is simple and gas lift valves can be retrieved by wireline
- Initial investment can be low:
  - if a source of high pressure gas is available
  - no longer true if compressors need to be installed
- No production problems when sand is present
- An additive can be injected (corrosion inhibitor) at the same time as the gas
- Suited to deviated wells
- Suited to starting up wells

Continuous gas lift (cont.)

▶ **Main drawbacks:**

- Need for bottomhole pressure that is not too low:

  ⇒ sometimes the artificial lift method has to be changed at the end of the well's lifetime
- The required injection gas volume may be excessive for wells with a high water cut
- Need for high pressure gas:
  - Can be costly
  - Increases safety risks
- Can not be applied if the casing is in bad shape
- Gas processing facilities (dehydration, sweetening) can compound compression costs
- Foaming problems may get worse
- Surface infrastructure is particularly expensive if wells are scattered over a large area
- Rather low efficiency, especially in a deep well

Well servicing & workover

Sommaire

- Main types of operations
- Wireline work
- Pumping
- Coiled tubing
- Snubbing
- Operation on killed wells

Main types of operations

Main types of operations

- **Means & types of operation**
  - Measurement operations
  - Maintenance operations
  - Remedial jobs & Workover operations

Means of operation

- **"Light" means of operation:**
  - Wireline unit
  - Pumping unit
- **"Heavy" means of operation:**
  - Coiled tubing unit
  - Snubbing unit
  - Pulling unit
  - Workover unit

On live wells (Wireline unit, Pumping unit, Coiled tubing unit, Snubbing unit)

On "killed" wells (Pulling unit, Workover unit)

Note:

- "Killed" well = inappropriate term, prefer "neutralised" well
- Coiled tubing, snubbing (pulling) units can be considered as "light" means compared to workover unit

Types of operation

- **Operations on the well itself**
- **Due to:**
  - Production considerations
  - Reservoir considerations
  - Trouble during an operations

⇒ **Measurement**

Maintenance

Remedial job & Workover

Wireline work

Wireline work

- Principle and area of application
- Surface equipment
- The wireline tool string
- Wireline tools

Principle

- **Work on a live producing or injecting well**
- **By means of a steel cable:**
  - Slick line or braided line
  - Electric cable
- **To run in and pull out:**
  - Tools (safety device, gas-lift valve, etc.)
  - Measurements instruments
- **Refer to figures here after for a general view of the equipment***

Principle : Example of wireline equipment

Principle : Example of wireline equipment (cont.)

Advantages, drawbacks & limitations

- **Advantages:**
  - No well killing
  - Operations performed quickly
  - Money saving:
    - Production hardly or not stopped
    - Pay zone not damaged (no killing)
    - Relatively low cost
- **Drawbacks and limitations:**
  - Requires highly qualified personnel
  - Difficult if highly deviated, sand production, viscous effluent
  - Not possible if hard deposits
  - Limited possibilities afforded by the cable:
    - Moderate tension
    - No rotation, no circulation

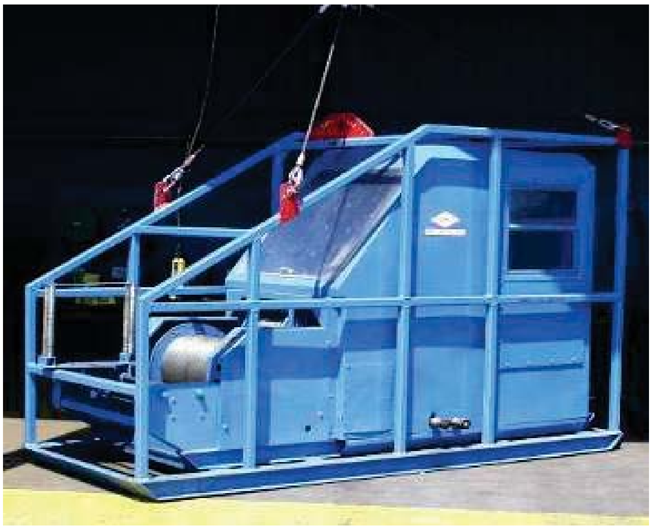
Main types of job

- **Monitoring and cleaning:**
  - The tubing (inside diameter, corrosion, etc.)
  - The bottomhole (sediment top, etc.)
  - ...
- **Measurement operations:**
  - Bottomhole temperature and pressure
  - Sampling
  - Locating interfaces
  - Production logs
  - ...
- **Running or pulling out tools & operations in the well:**
  - Safety valves, bottomhole choke, plugs
  - Gas-lift valve
  - Actuating circulating device
  - Fishing
  - Perforating
  - ...

Cable

- **Slick line:**
  - 0.066", 0.072", 0.082", 0.092" et 0.105"
- **Braided (or stranded) line**

Hydraulic winch and its motor or engine



- Drum
- Depth indicator
- Motor/engine and transmission:
  - Mechanical
  - Hydraulic

Required winch horsepower

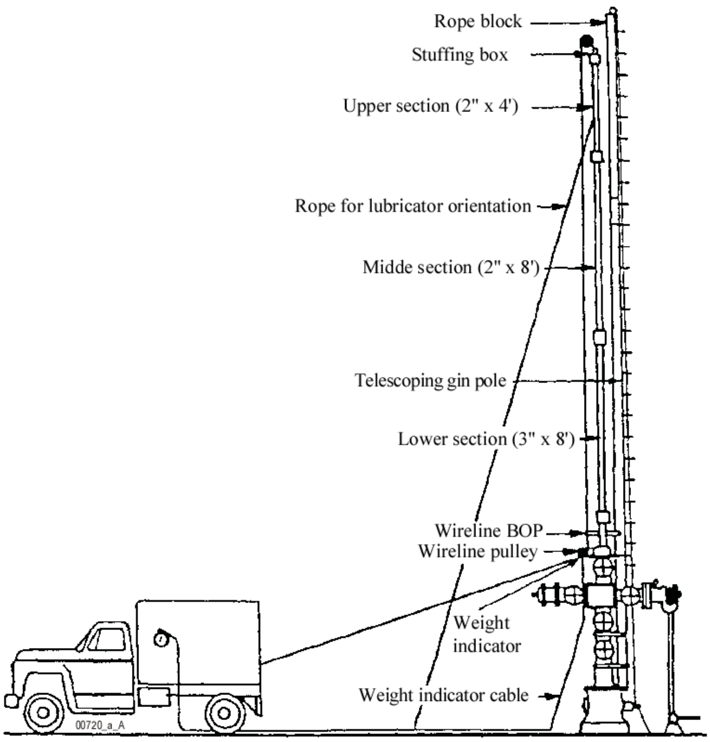
Winch horsepower	Recommended maximum depth			
	without jarring		with jarring	
	(m)	*(ft)*	(m)	*(ft)*
9	2000	*6700*	500 (by hand)	*1700*
14	3000	*10,000*	2000	*6700*
22	5000	*16,700*	2500	*8300*
48	5000	*16,700*	5000	*16,700*

Recommended speeds

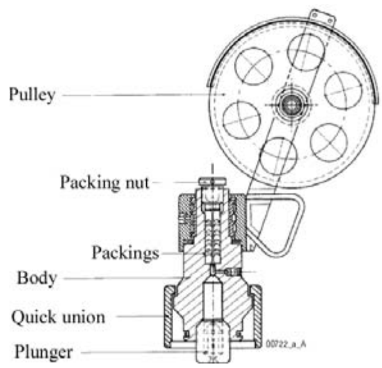
Operations	Running in	Pulling out
Amerada recorder	1 m/s *(3 ft/s)*	1 m/s *(3 ft/s)*
Sampler	1 m/s *(3 ft/s)*	maximum
Well control	2 m/s *(7 ft/s)*	2 m/s *(3 ft/s)*
Setting mandrels	Depending on well	Depending on well
Paraffin removal	Depending on well	Depending on well
Caliper	Unimportant	20 to 22 m/min *(70 ft/min)*

Surface equipment lay-out

Lubricator, Stuffing box & Double BOP



Lay-out & Lubricator



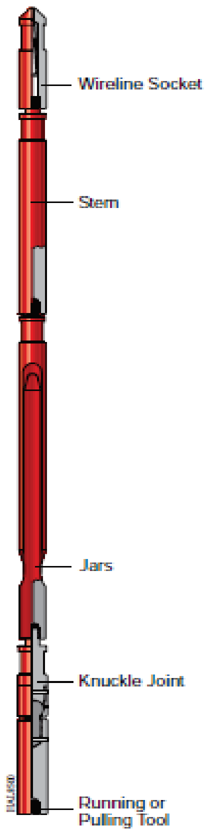
Stuffing box & Double BOP

Lubricator

- **Stuffing box(*)**
- **Tool trap**
- **BOP or wireline valve(*)**

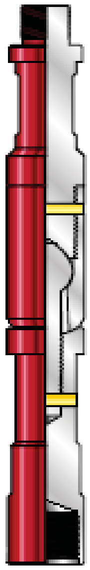
(*): If braided line:
- Special stuffing box (grease/oil injection control head)
- Special dual BOP (with lower set of rams inverted and grease injection between them)

Wireline tool string

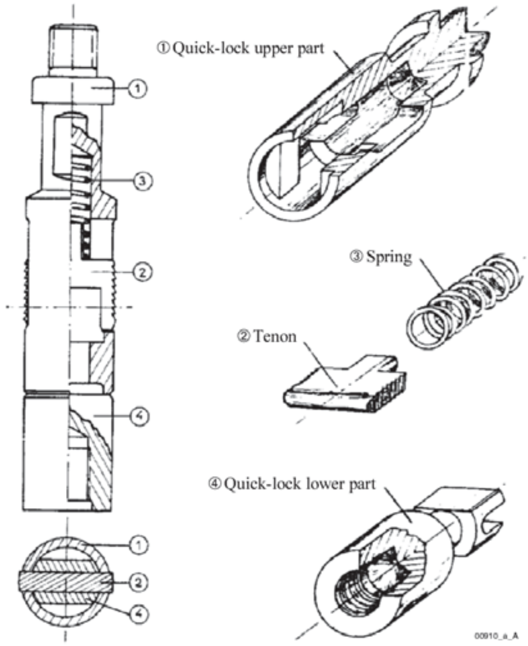


- rope socket
- stems:
  - 2, 3 or 5 ft (0.61, 0.91 or 1.52 m)
- jars
  - Mecanical
  - Hydraulic
- knuckle joint
- Miscellaneous components
  - quick lock coupling
  - ...

Knuckle joint & Quick-lock coupling



Knuckle joint



Quick lock coupling

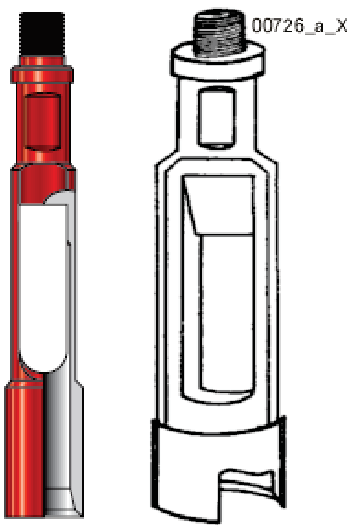
Main categories of wireline tools

- Checking and maintenance tools
- Running (or setting) and pulling tools
- Lock mandrels, downhole tool and other particular tools
- Fishing tools

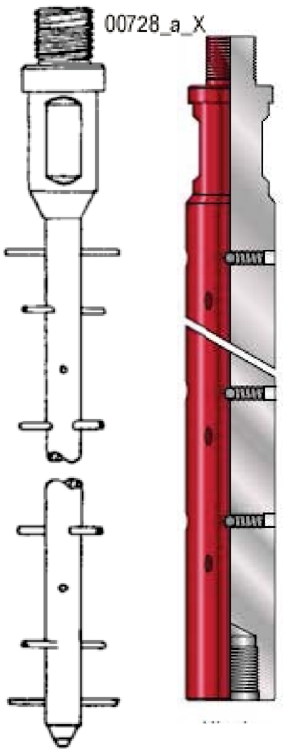
Checking and maintenance tools

- gauge cutters*
- scratcher*
- swaging tool*
- calliper
- Tubing end locator*
- sand bailer*
- ...

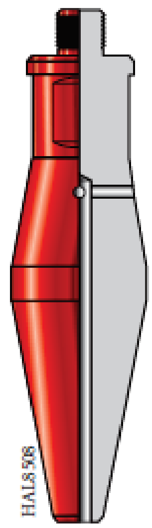
Some checking and maintenance tools



Gauge cutter

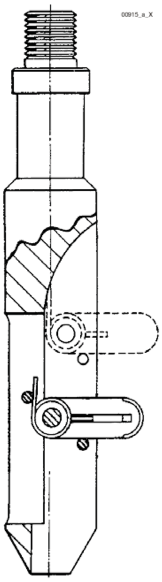


Scratcher
Nipple brush

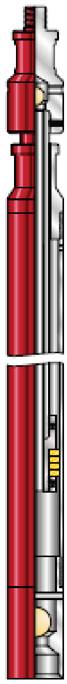


Swaging tool

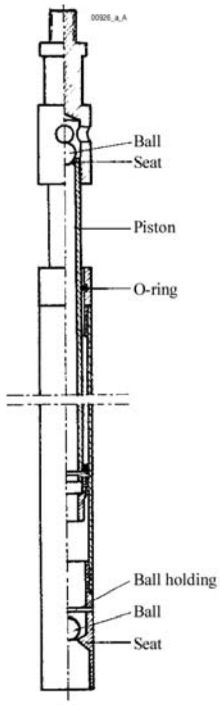
Some checking and maintenance tools (cont.)



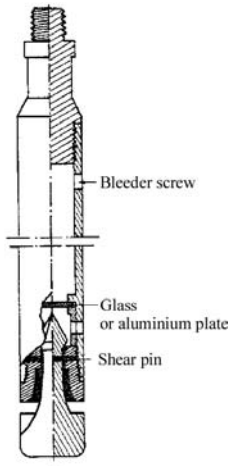
Tubing end locator



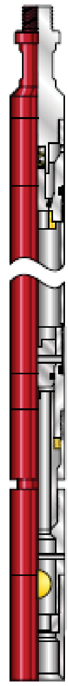
Pump (Sand) Bailer



(a)



(b)



Hydrostatic Bailer

Bailer

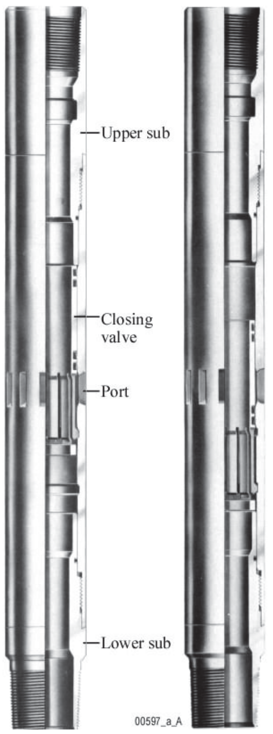
Running (or setting) and pulling tools

- **Mains kind of tools:**
  - Running tools
  - Pulling tools
  - Combination tools
- **Tools equipped with pins:**
  - Two kind of shear pins:
    - To attach the downhole tool directly to the running tool
    - To release dogs under normal operating conditions or as a safety precaution
  - Pins sheared by*:
    - Upward jarring
    - Downward jarring

Other tools

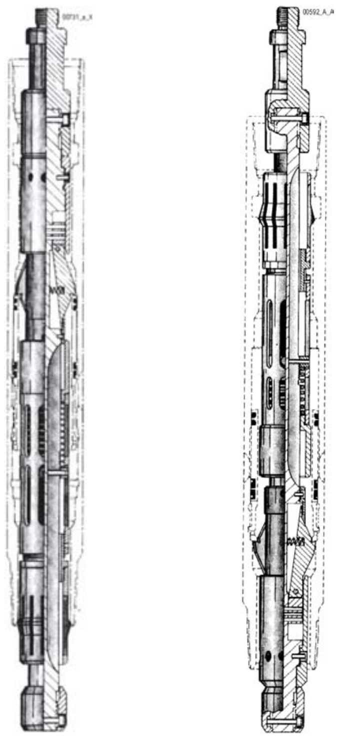
- **Particular tools:**
  - Shifting tool* : for operating sliding sleeve
  - Kickover tool* : for side pocket mandrel
  - Hanging tool without jarring (for recorders)
  - Swabbing tool
  - Perforator:
    - Mechanical
    - Explosive charge
  - ...

Sliding sleeve & Shifting tool



Open closed

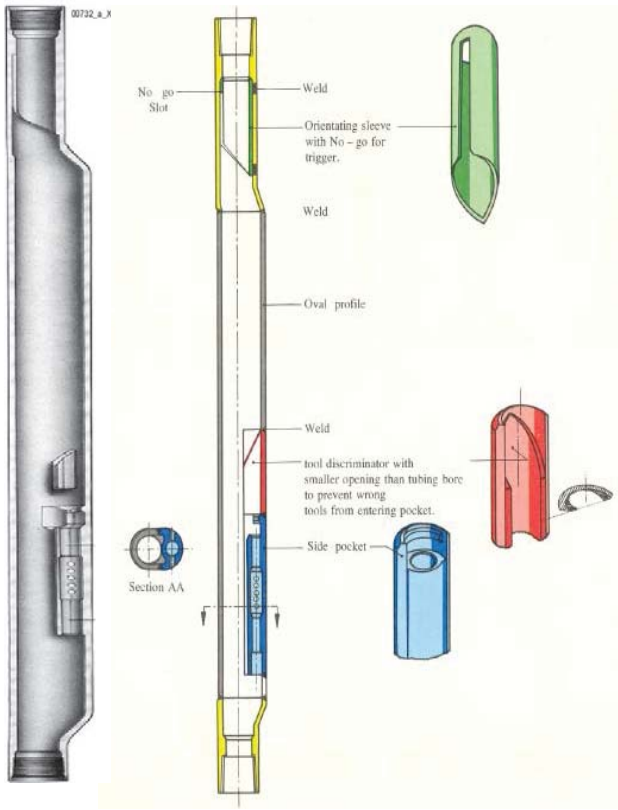
Sliding sleeve

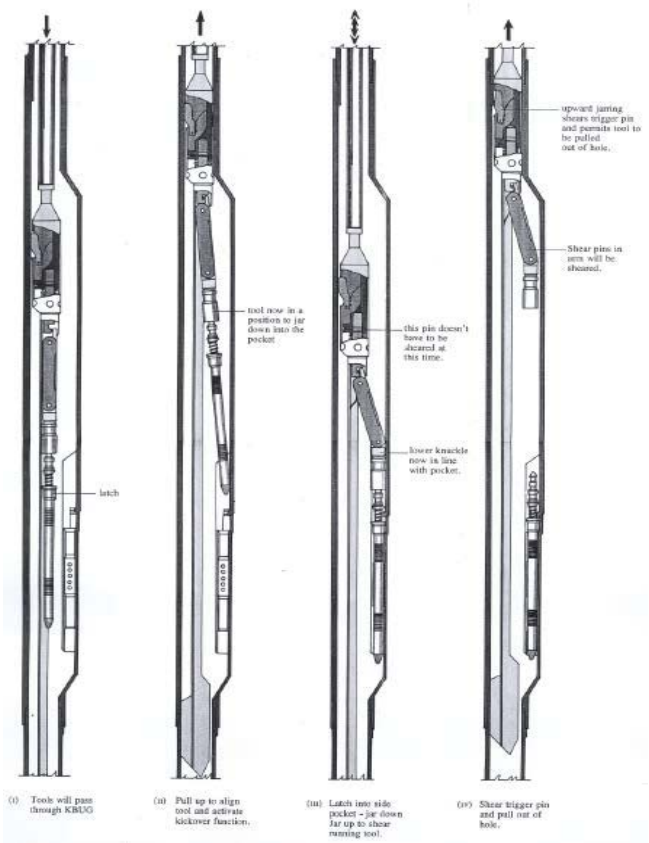


Closing Opening

Shifting tool

Side pocket mandrel & Kickover tools

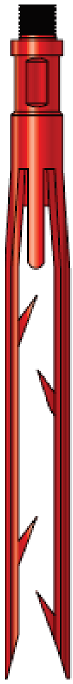




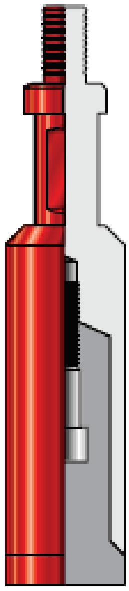
Fishing tools

- **Wireline cutter**
- **Wireline finder**
- **Wireline grab***
- **Impression block***
- **Overshot***
- **Magnet**
- **…**

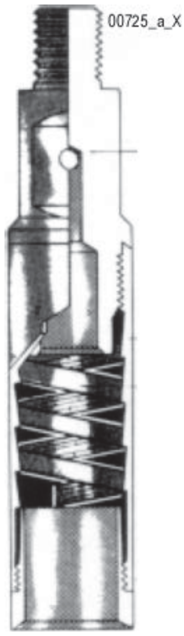
Some fishing tools



Wireline grab



Impression block



Overshot

Pumping

Principle

- **To connect a pump to the wellhead in order to inject a treatment fluid into:**
  - The tubing
  - The vicinity of the borehole

In fact

- **This practice is not usually well suited to oil wells:**
  - Necessity to squeeze the effluent in the tubing but:
    - Its needs injectivity
    - Its may damage the pay zone
  - Or to circulate through a circulating device but:
    - Risk of leak afterwards
    - If direct circulation, . . .
    - if reverse circulation, . . .
- **However it can be advantageous for gas well:**
  - Have fewer injectivity problems
  - Treatment fluid can settle down by gravity

Coiled tubing

Coiled tubing

- Principle and area of application
- Coiled tubing equipment
- Operating considerations

Principle and area of application

- **To run a continuous pipe into a live well:**
  - A pipe coiled up on a reel
  - With the help of an injection head
  - Through a safety assembly:
    - Stripper
    - BOP stack
- **Refer to figures here after for a general view***

Coiled tubing unit: General view

Coiled tubing unit: General view (cont.)

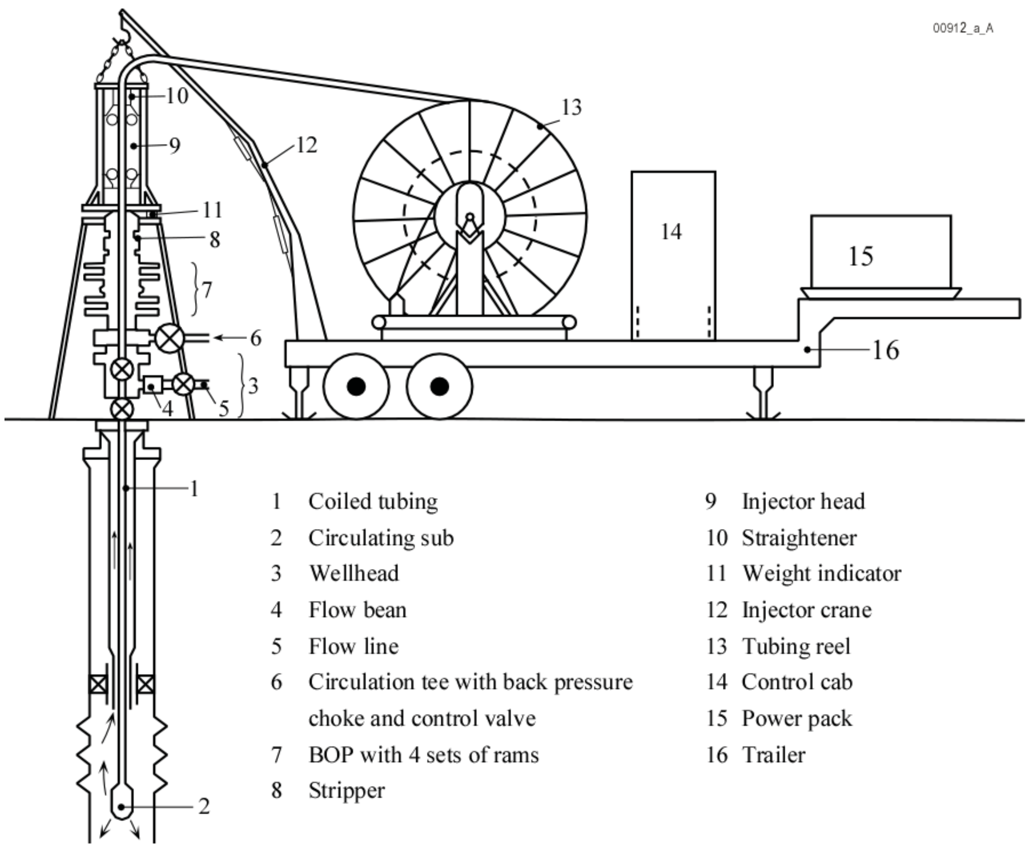
Area of application

- **Changing the hydrostatic pressure:**
  - Circulating a "light" fluid:
    - Underbalanced perforation
    - Well start-up
  - Gas injection:
    - Well kick-off (nitrogen)
    - "Temporary" gas lift
  - Through diameter optimisation
  - Circulating a "heavy" fluid:
    - Well killing
- **Well cleaning:**
  - Tubing: scale, wax or salt removal, etc.
  - Bottomhole: sand washing, etc

Area of application (cont.)

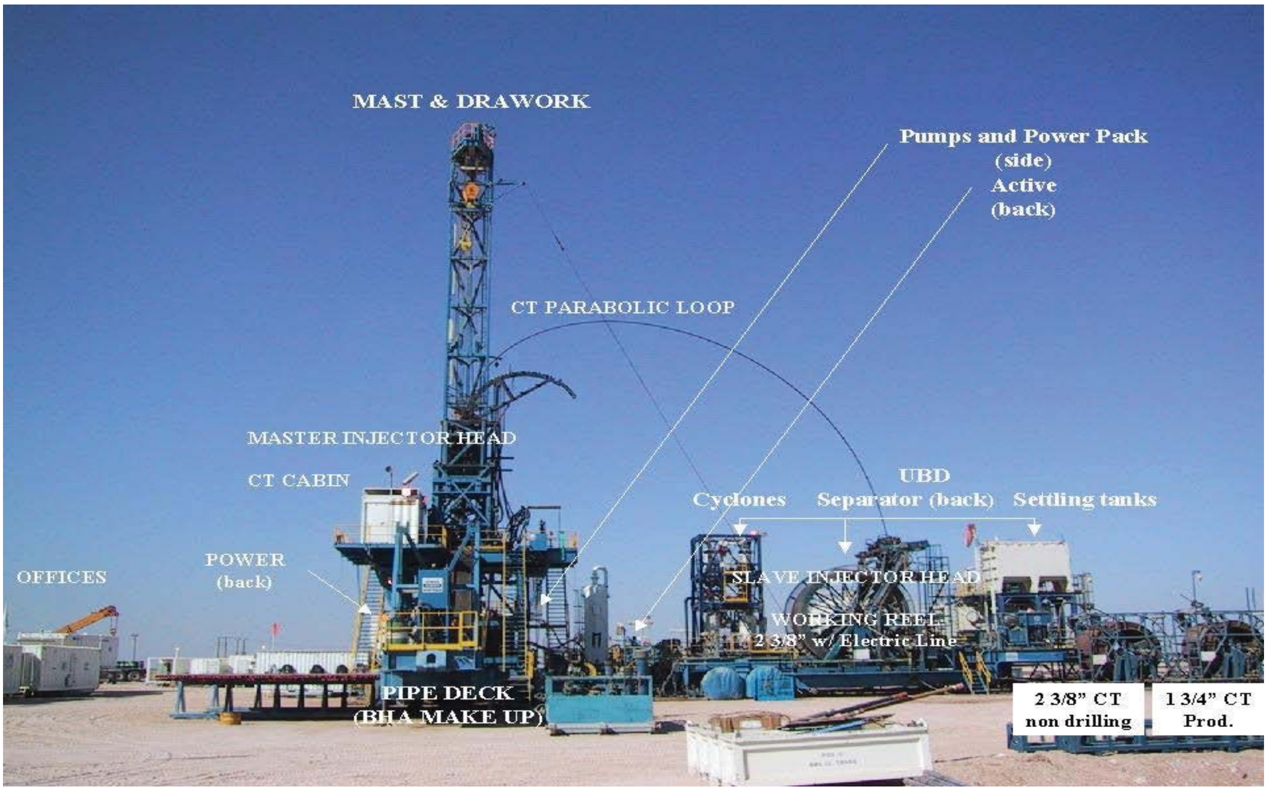
- **Matrix stimulation treatment:**
  - Acidizing, solvent
- **Horizontal well:**
  - Well logging and perforating
- **Other operations:**
  - Fishing job
  - "Temporary" concentric tubing: inhibition injection, gas lift, etc.
  - Cementing
  - Underreaming
  - Drilling

Coiled tubing equipment: General view

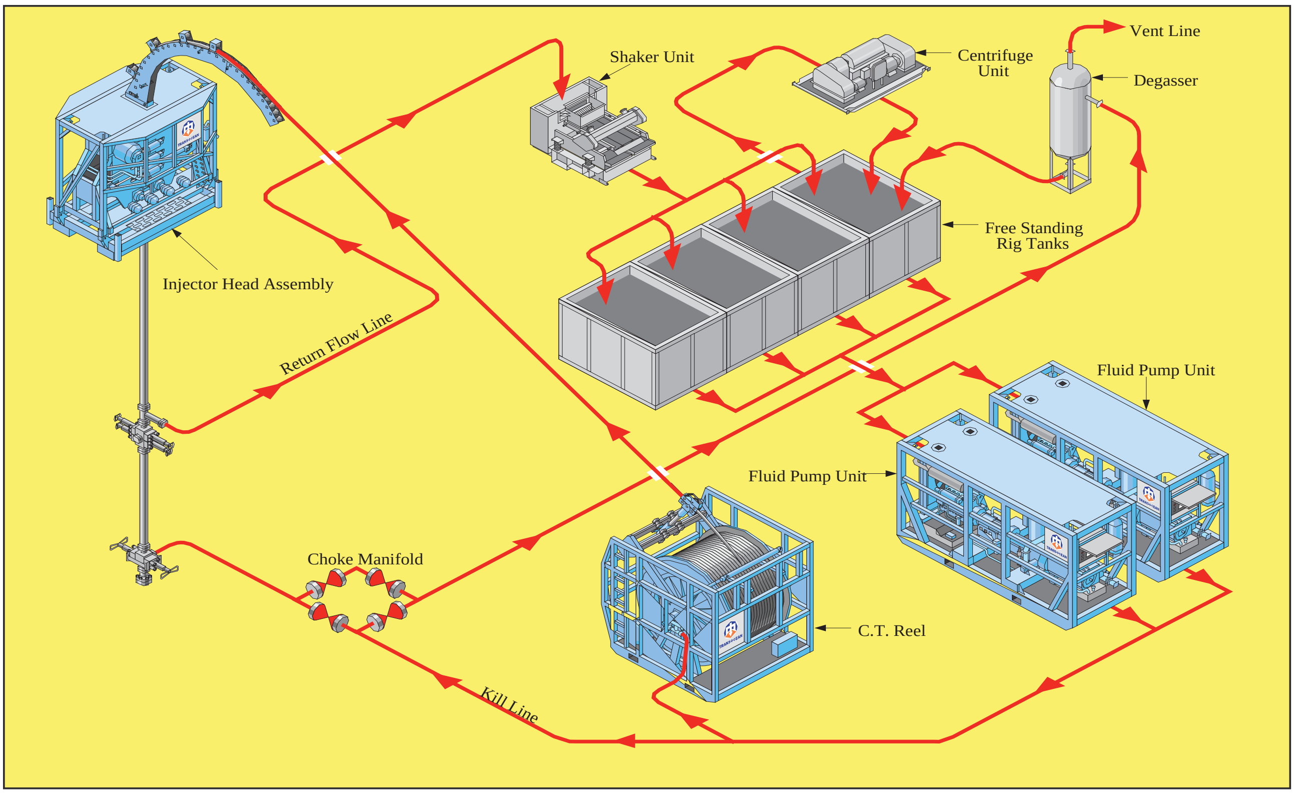


1 Coiled tubing
2 Circulating sub
3 Wellhead
4 Flow bean
5 Flow line
6 Circulation tee with back pressure choke and control valve
7 BOP with 4 sets of rams
8 Stripper
9 Injector head
10 Straightener
11 Weight indicator
12 Injector crane
13 Tubing reel
14 Control cab
15 Power pack
16 Trailer

Coiled tubing equipment: General view (cont.)



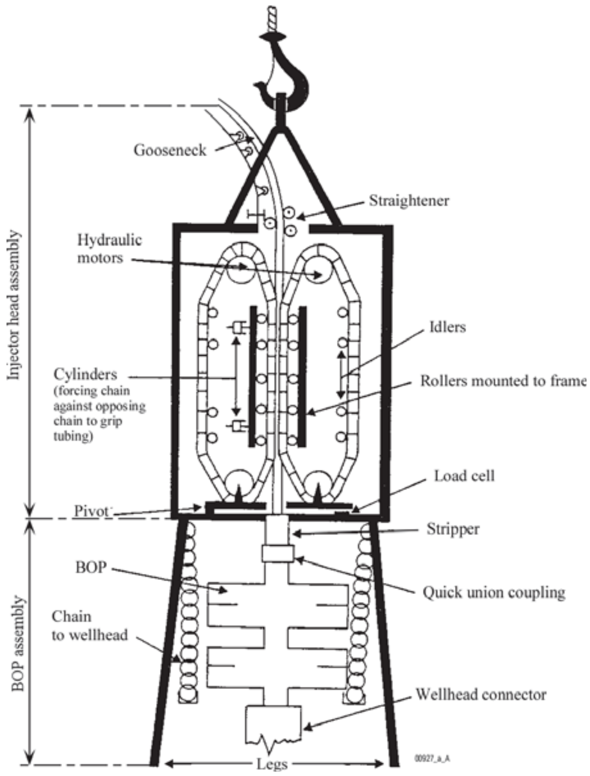
Coiled tubing equipment: General view (cont.)



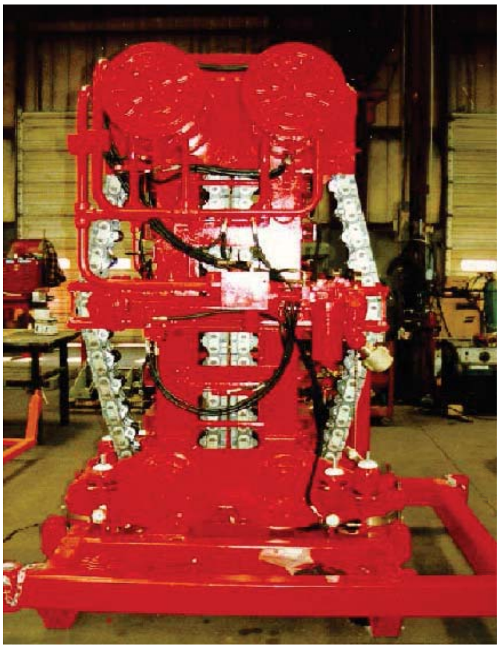
Reel & Pipe

- **Reel:**
  - Ø: 2.5 m *(8 ft)*
    ⇒ 6 000 m of 1" *(20,000 ft)*
  - Driven by an hydraulic motor
  - Rotating seal ring
- **Pipe:**
  - Continuous metal pipe (longitudinal welding)
  - Jointed together by radial welding
  - Ø: 3/4", 1", 1 1/4", 1 1/2", etc.*

Injector head & Safety assembly

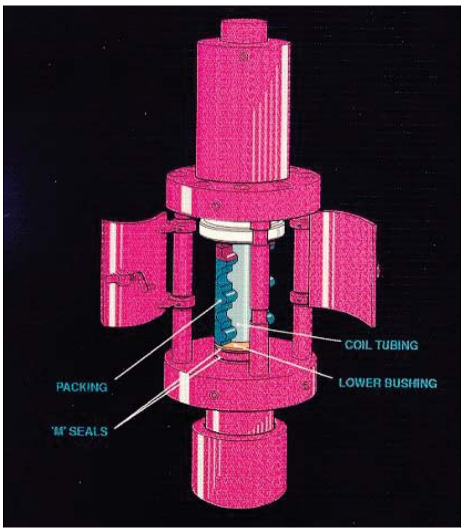


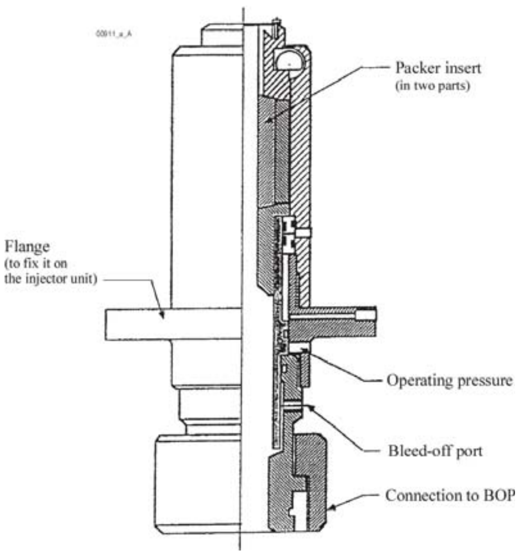
Injector head



Gooseneck
Two chains with half slips
⇒ friction
Activated hydraulically

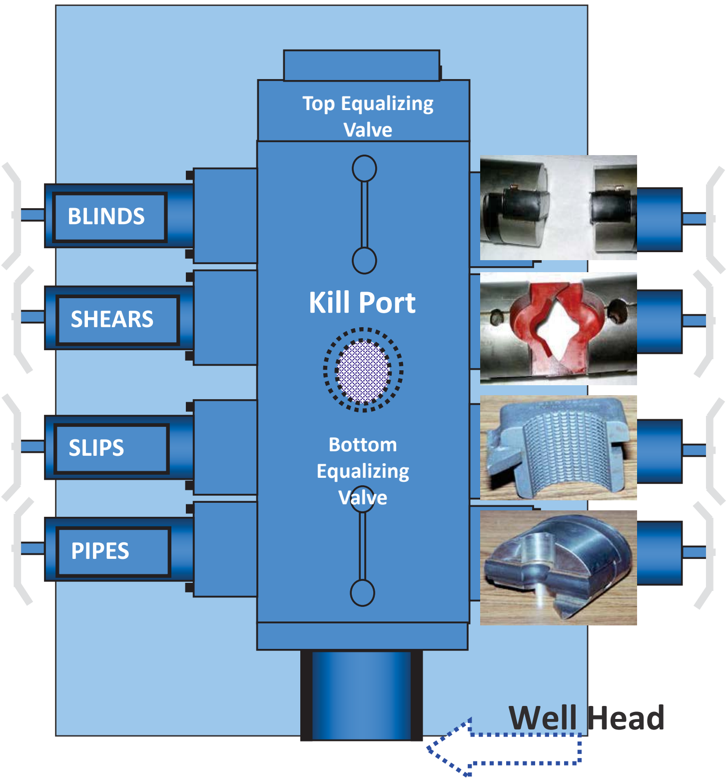
Safety assembly (Stripper & BOP): Stripper





- **Stripper :**
  - Sealing elements:
    - In two parts
    - Can be changed during stripping
    - Actuated hydraulically

Safety assembly (Stripper & BOP): BOP



- **BOP :**
  - Blind rams
  - Cutters
  - Slip rams
  - Pipe rams
  - Equalising and circulating valves

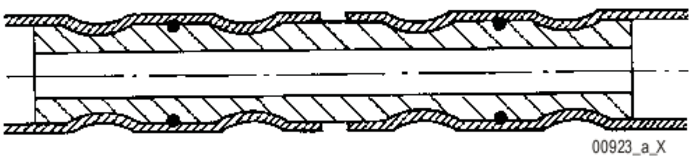
Procedure to cut the coiled tubing

- **Stop coiling up or down**
- **Close slips rams & pipe rams**
- **Cut the coiled tubing**
- **Coil up the upper part of the coiled tubing**
- **Close blind rams**
- **Circulate through the kill line to neutralise the well**

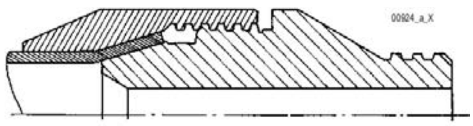
Ancillary surface equipment & downhole accessories

- **Ancillary surface equipment:**
  - Hydraulic crane
  - Hydraulic power pack
  - Control cab
  - Nitrogen unit
- **Downhole accessories*:**
  - Connecting devices
  - Check valves
  - Jet tools
  - Hydraulic motors
  - Overshots
  - …

Connecting devices

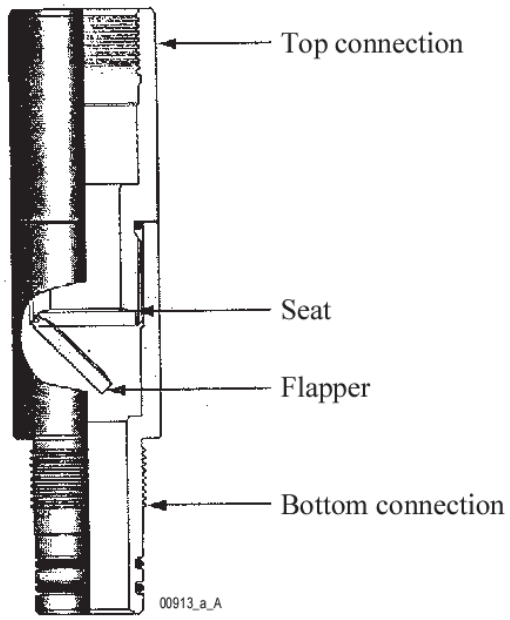


Crimping splice/roll-on connector

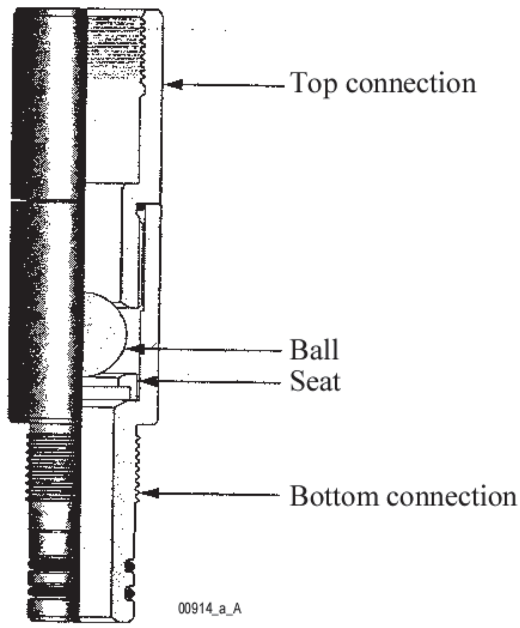


Screwed connector

Check valves

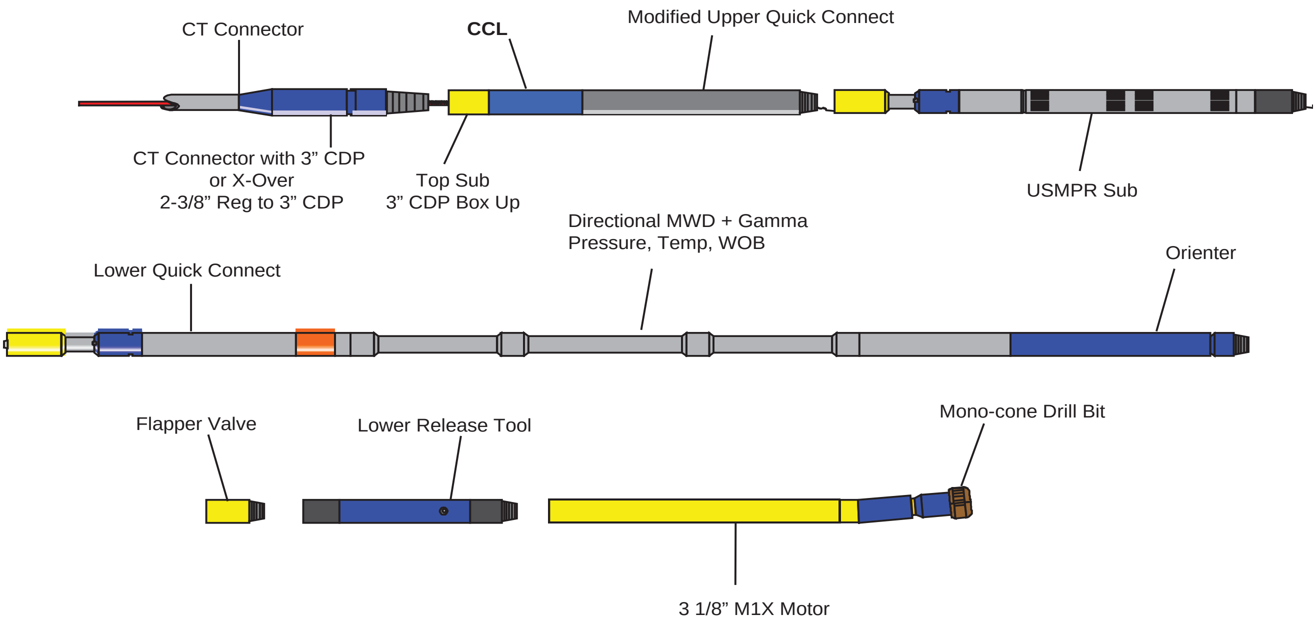


Flapper check valve



Ball and seat check valve

Equipment to drill with a coiled tubing unit



Snubbing

Snubbing

- Principle and area of application
- Snubbing equipment
- Operating considerations

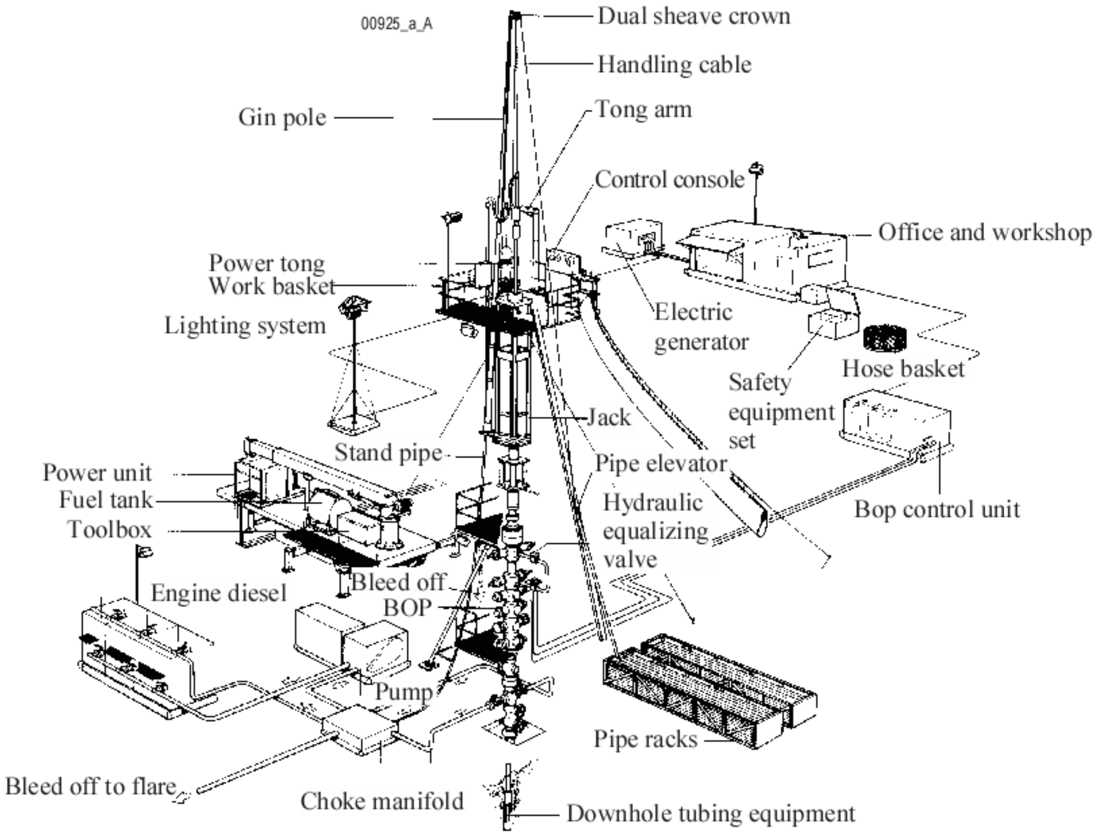
Principle and area of application

- **Principle:**
  - To run "conventional" tubing pipes (each length screwed on the previous one) into a live well
- **Need for:**
  - A check valve at the bottom of the tubing
  - A sealing system on the Christmas tree
  - A handling system
- **Refer to figures here after for a general view***

Snubbing: General view

Snubbing: General view (cont.)

Snubbing: General view (cont.)



Work basket

Advantages, Drawbacks & Area of application

- **Advantages (compared to coiled tubing):**
  - The pipe does not work in the plastic range
  - Possibility to rotate from the surface
  - By the past: bigger diameters available
- **Main drawbacks (compared to coiled tubing):**
  - More dangerous for the team
  - Heavier and bulkier
  - Tripping takes longer
- **Area of application:**
  - As with a coiled tubing unit of big diameter

  and

  - Can perform or make easier some special operations:
    - Fishing job with fishing tool requiring small right or left rotation
    - Pulling out the tubing string without having to neutralise the well
    - Etc.

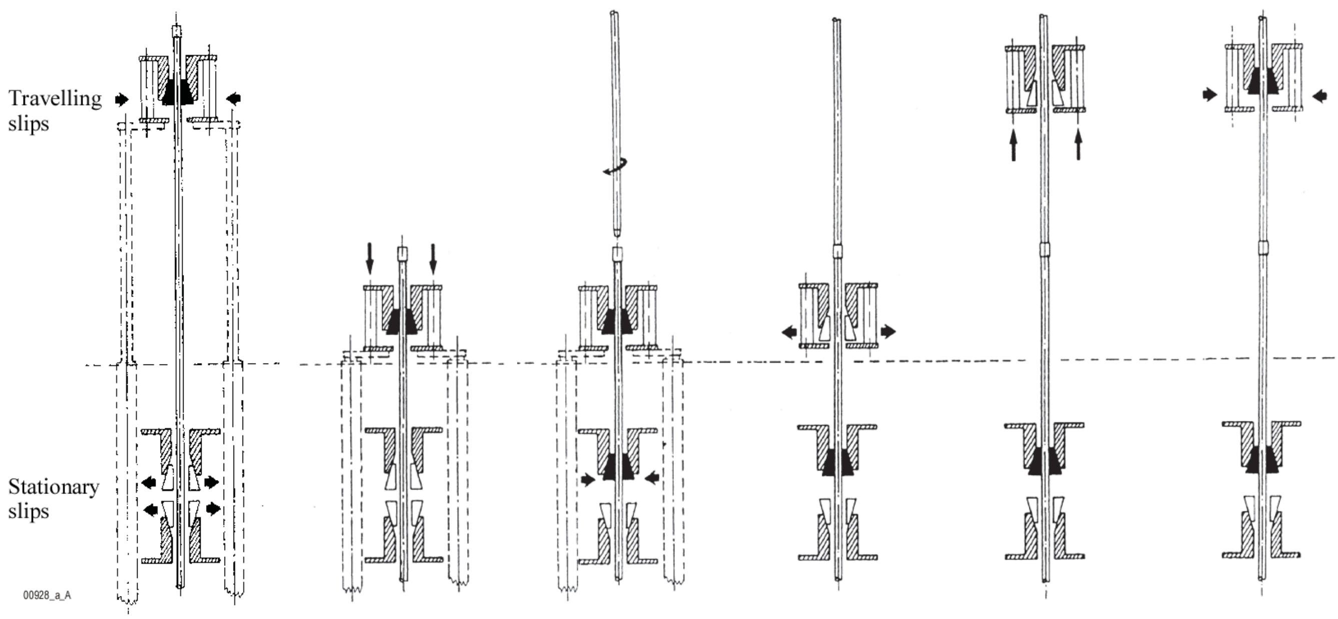
Snubbing equipment - Pipe handling system

- **Must allow to:**
  - Push the pipe into the well

  Or

  - Support it
- **3 phases :**
  - Snub (or "light pipe ")*
  - Equilibrium(balance point)
  - Strip (or "heavy pipe ")

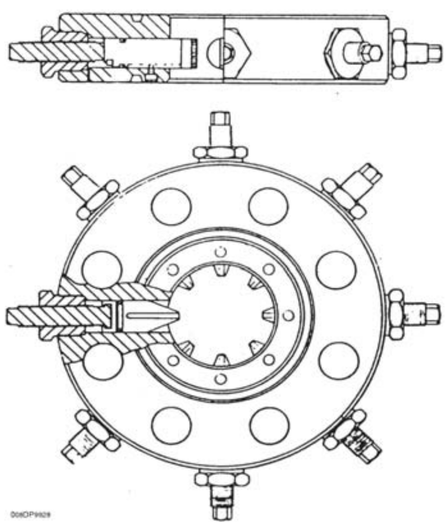
Snub phase running in sequence



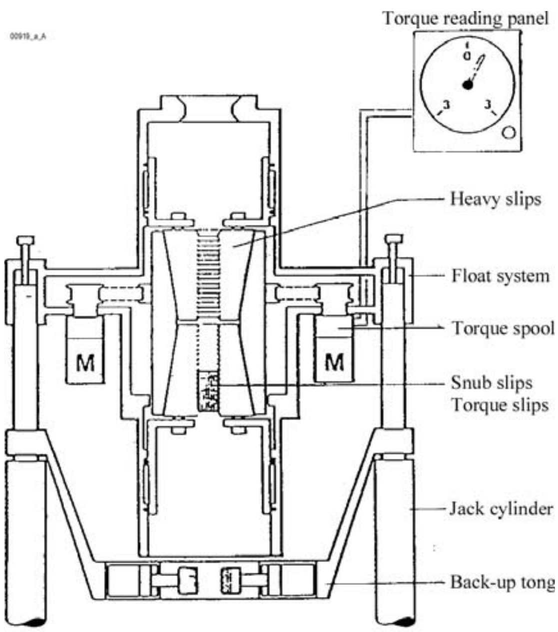
Pipe handling system (cont.)

- Double acting jacks
- Stationary slips
- Travelling slips
- Access window
- Hanger flange*
- Rotary table*

Hanger flange & Rotary table



Hanger flange

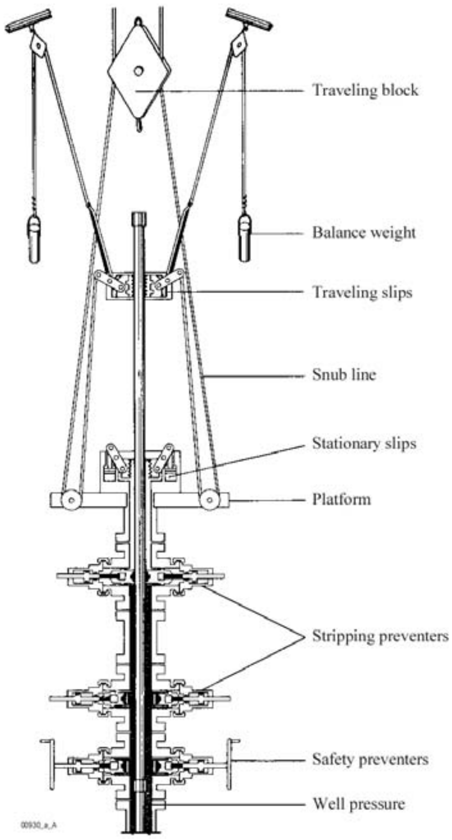


Rotary table

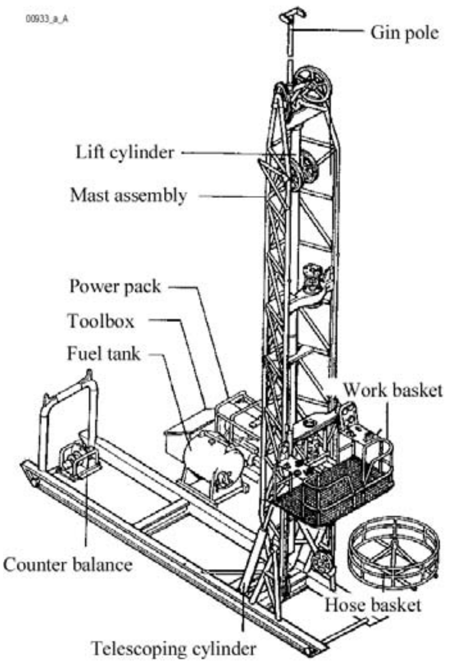
Types of snubbing units

- (Cable unit)*
- Long stroke unit*
- Short stroke unit*

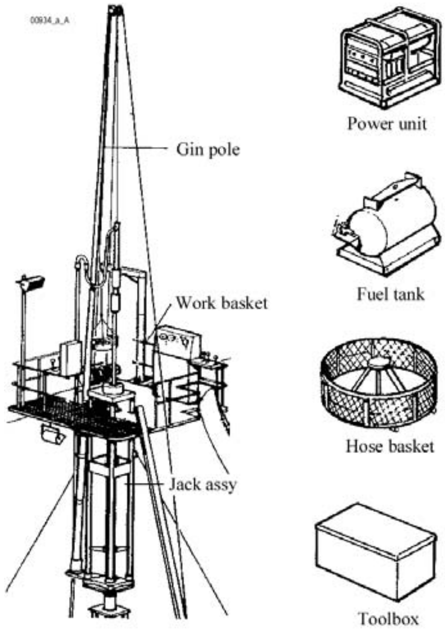
Rig assist snubbing unit (cable unit)



Snubbing unit with hydraulic jacks



Long stroke



Short stroke

Pipe handling capacity

- **Maximum stroke (if no buckling problem):**
  - Long stroke unit: ≈ 11 m *(36 ft)*
  - Short stroke unit: ≈ 3 m *(8 to 10 ft)*
- **Maximum hoisting capacity (pull):**
  - 80 000 to 300 000 lb. and more (350 to 1 300 kN)
- **Maximum snubbing capacity (push):**
  - Usually: half of the hoisting capacity
- **Tubing size range: at least 3 1/2", eventually 7 5/8" or more**
- **Tripping speed:**
  - Stripper only: 10 m/min *(30 ft/min)*
  - Through BOP: 2.5 m/min *(7.5 ft/min)*
- **Performance of long & short stroke units: examples***

Long stroke unit performance data

PERFORMANCE DATA			
	MODEL HRL 75	MODEL HRL 120	MODEL HRL 300
Maximum Hang Load (pull)	75,390 lb	120,750 lb	314,970 lb
Maximum Snub Load (push)	32,985 lb	63,030 lb	164,190 lb
Stroke	36'	36'	36'
Tubing Size Range (1)	3/4 to 3 1/2" OD	3/4 to 5 1/2" OD	3/4 to 7" OD
Rotary Torque (standard)	1000 ft/lb	1000 ft/lb	3500 ft/lb
Block Speed Down (max.)	360 ft/min	259 ft/min	188 ft/min
Block Speed Up (max.)	280 ft/min	206 ft/min	205 ft/min
Horse Power	235 HP	235 HP	Twin 308 HP
Engine (standard)	6V71N	6V71 N	Twin 8V71 N
Cylinder (one)	8" Bore – 6"Rod – 18' Stroke	10 1/8" Bore – 7" Rod – 18' Stroke	11 9/16" Bore – 8" Rod – 18' Stroke
Full Guide Tube	yes	yes	yes
Performance	100 to 130 joints per hour in ideal conditions		

(1) Tubing size range can be increased if hang weight remains within weight range of particular unit

Short stroke unit performance data

PERFORMANCE DATA			
	MODEL HRL 150	MODEL HRL 225	MODEL HRL 300
Maximum Hang Load (pull)	150,720 lb	235,560 lb	318,360 lb
Maximum Snub Load (push)	91,720 lb	100,000 lb	100,000 lb
Stroke	8' – 10'	8' – 10'	8' – 10'
Tubing Size Range (1)	3/4 to 3 1/2" OD	3/4 to 5 1/2" OD	3/4 to 7" OD
Rotary Torque (standard)	1000 ft/lb	3500 ft/lb	3500 ft/lb
Jack Speed Down (light load)	259 ft/min	520 ft/min	369 ft/min
Jack Speed Up (light load)	404 ft/min	536 ft/min	410 ft/min
Horse Power	235 HP	320 HP	320 HP
Engine (standard)	6V71N	8V71 N	8V71 N
Cylinder (four)	4" Bore – 2" 1/2 Rod	5" Bore – 3" 1/2 Rod	5 13/16" Bore – 4" Rod
Full Guide Tube	yes	yes	yes
Performance	80 to 100 joints per hour in ideal conditions		

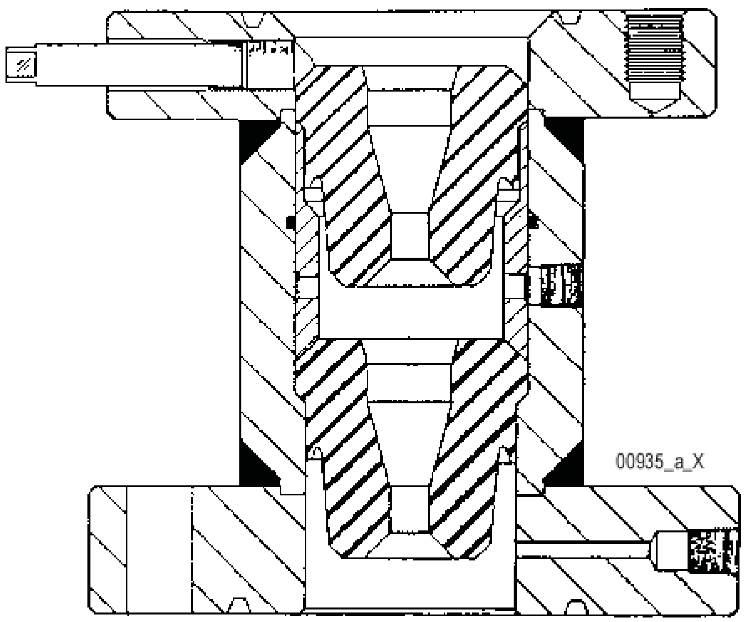
1) Tubing size range can be increased if hang weight remains within weight range of particular unit

Wellhead safety stack

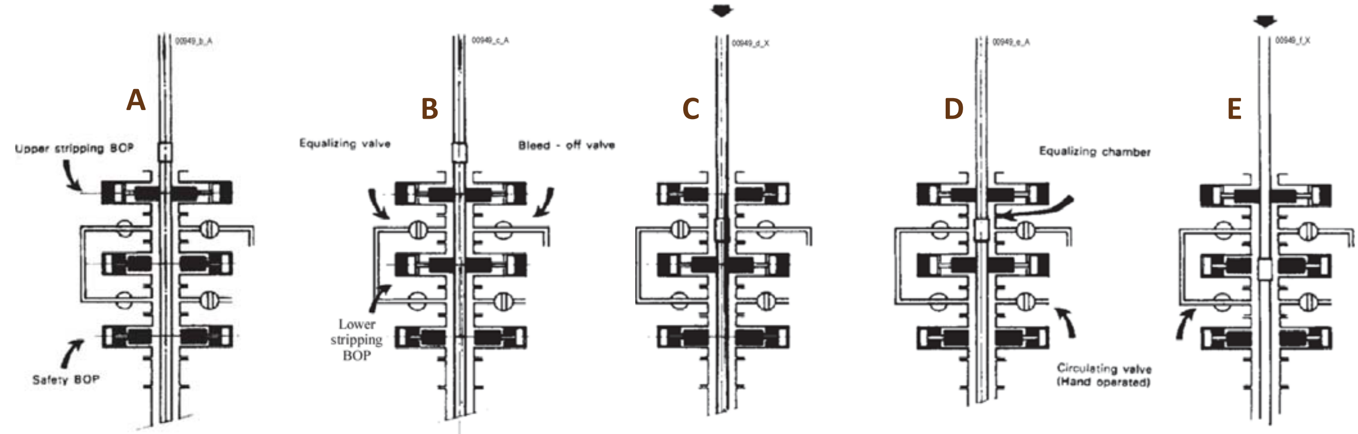
- **Basic components:**
  - Stripper (cup type)*
  - Upper stripping BOP
  - Spacer spool
  - Lower stripping BOP
  - Safety BOP
  - Equalising and bleed-off lines
- **Other components:**
  - Hanger flange
  - Spherical or annular type BOP
  - Shear ram BOP
  - Blind ram BOP
  - Extra stripping or safety BOP
- **General view***

Refer to :
" BOPs sequence when running pipes into the hole "*

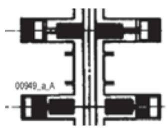
Stripper (cup type)



BOPs sequence when running pipes into the hole



Phase	A	B	C	D	E
Upper stripping BOP	closed	-	① opens	① closes	-
Lower stripping BOP	open	① closes			① opens
Safety BOP	open	remains open during stripping			
Equalizing valve	open	② closes	-	③ opens	-
Bleed-off valve	closed	③ opens	-	② closes	-
Tubing coupling	run in one foot above upper BOP	-	② run in until situated between "upper" and "lower" stripping BOP	-	② run in until next coupling arrives



Safety stack

Hydraulic power unit

- **Main pumps for the jacks**
- **Auxiliary pump:**
  - BOP
  - Equalising and bleed-off valves
  - Slips
  - Winch
  - Rotary table
  - …

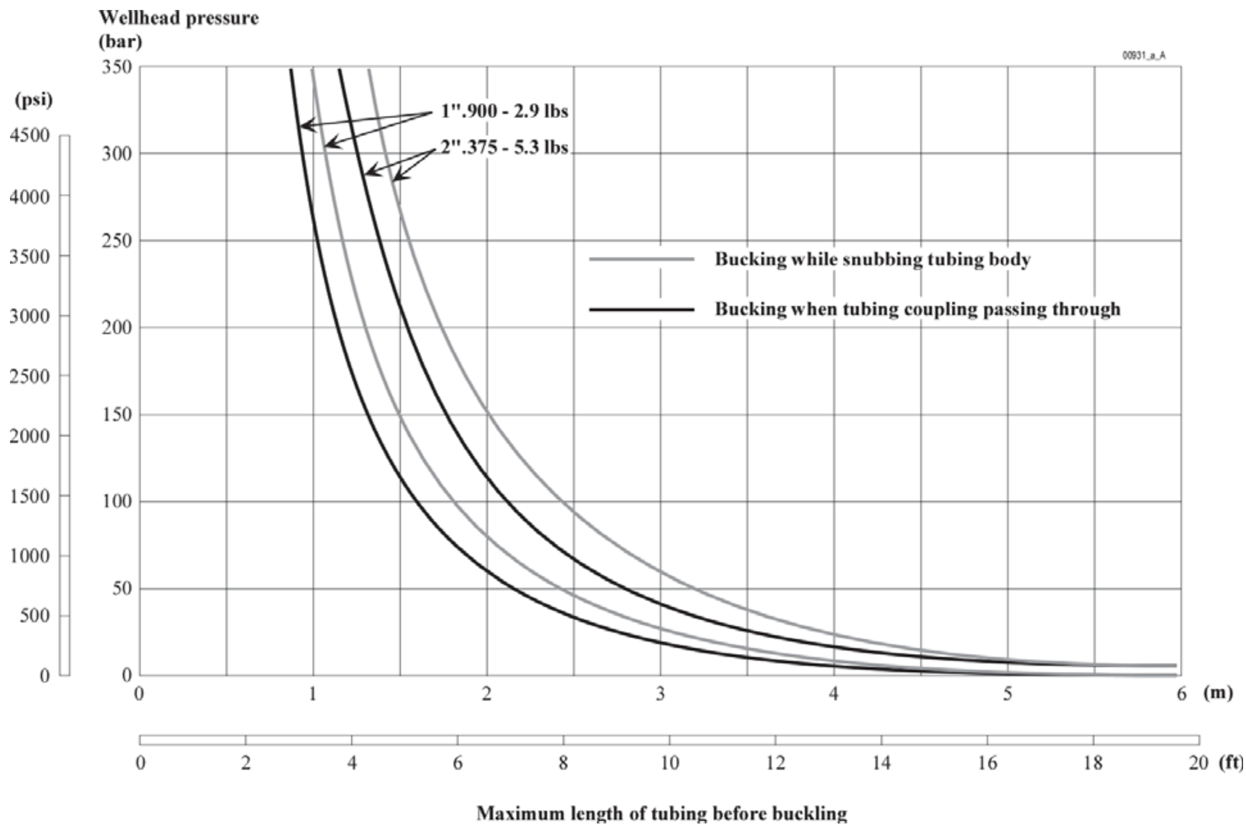
Downhole accessories

- **Check valves:**
  - Screwed on the tubing, or
    In a landing nipple
  - Placed far enough from the end of the pipe
    ⇒ Warning signal
- **Jetting tools**
- **Drilling bit**
- **Hydraulic motor**
- **Fishing tools**

BOPs sequence when running pipes into the hole & Buckling

- **BOPs sequence when running pipes into the hole (for memory)**
- **Buckling:**
  - During the snub phase
  - Maximum tendency at:
    - The beginning of the running in
    - The end of the pulling out
  - Function of:
    - Wellhead pressure
    - Pipe size
    - Illustration *

Buckling at the beginning of the running in



Jumping over the balance point (when the travelling system has only one set of single acting slips)

- **When running in:**
  - Pipe filling
  - Action on the wellhead pressure
- **When pulling out:**
  - Action on the wellhead pressure
- **Example** *

Tripping speed

- **Stripper only:**
  - 10 m/min (30 ft/min)
- **Through BOPs:**
  - 2.5 m/min (7.5 ft/min)

Operation on killed wells

Operation on neutralised wells

- Preamble
- Means of acting on killed wells
- General procedure of an operation
- Workover on depleted reservoirs
- Fishing tools

Preamble

- **A workover is usually required if:**
  - The tubing and/or its equipment have to be pulled out
- **So:**
  - Necessity to "kill the well" beforehand, or, more exactly to "neutralise the well"
- **Techniques used during the intervention:**
  - Basically, the same as during initial completion
- **However, particular care:**
  - To proceed to the well control
  - To redefine the new completion

Means of acting on neutralised wells

- **Depend mainly on:**
  - Depth of the well
  - Equipment installed in the well
  - Job that needs to be done
- **Types of units:**
  - Crane
  - Pulling* or servicing units
  - Workover rig
- **Criteria of choice:**
  - Hoisting capacity
  - Pumping capacity & safety equipment
  - Possibility of rotation & ancillary equipment
  - Daily cost
  - Geographical availability

Pulling operation

- The well is no more naturally flowing but produced by pumping
- Usually, the Christmas tree is "simplified"
- No installation of safety device for the intervention (no BOP, …)
- Pulling operations consist of:
  - Pull out pumps (electrical, mechanical)
  - Change the sucker rods (mechanical pumping)
- The pulling unit is just a "crane"

Means of acting on killed wells (cont.)

- **Beware, necessity of an appropriate specialised equipment:**
  - Specific safety equipment (BPV, gray valve, etc.)
  - Hoisting, pipe make up & fishing equipment suitable for small diameter drill pipe and tubing
  - Wireline equipment
  - Etc.

General procedure of an operation

Mainly function of:

- Equipment installed
- Its condition
- What needs to be done
- How the operation is actually going on

Preamble (cont.)

However, main steps involved:

- (a) : Preparing the well
- (b) : Putting the well under safe conditions
- (c) : Installing the servicing or workover unit
- (d) : Neutralising the well
- (e) : Replacing the Xmas tree by the BOPs
- (f) : Removing completion equipment
- (g) : Downhole operations
- (h) : Running in completion equipment
- (i) : Replacing the BOPs by the Xmas tree
- (j) : Well start-up
- (k) : Moving out the servicing or workover unit

Note: possibly, inversion between: - steps (b, c) and step (d)
- step (j) and step (k)

Preamble (cont.)

- **More tricky operations (from a safety point of view):**
  - Installing the servicing or workover unit
  - Neutralising the well
  - Replacing the Christmas tree with the BOPs
  - "Unsetting" the packer

  And:
  - Perforating ou reperforating
  - High pressure (…) pumping
  - Replacing BOPs by the Christmas tree
  - Well start-up
  - Moving out the servicing unit

Preparing the well before the servicing or workover unit arrives

- **Wireline checking:**
  - Gauge cutter
  - Sediment tag
  - Etc.

Preparing the well

before the servicing or workover unit arrives (cont.)

- **Pressure testing:**
  - Wellhead:
    - $P_{test} > P_{max}$ planned during neutralisation
    - With a safety factor (1.5 if possible)
    - Depending on the actual state of the equipment
    - P_{test} < WP of the weakest equipment
  - Tubing:
    - See above + acceptable ΔP on the plug
    - Careful: plug retrieval: potential problem
  - Annulus:
    - Preferably, at $P \leq P_{test}$ during initial completion

Preparing the well

before the servicing or workover unit arrives (cont.)

And, possibly:

- **Circulating device opening:**
  - To neutralise the well (if neutralisation scheduled by circulating)
  - By wire line:
    - Opening of the circulation device
    - Or, failing that, perforating the tubing

Putting the well(s) under provisional safe conditions

- **Wells involved:**
  - Function of the installation configuration (cluster):
    ⇒ nearby wells
- **Placing "plugs":**
  - Downhole plug
  - SCSSV
  - BPV
  - Etc.

  Normally, at least two among which one downhole; if not, workover fluid
- **Well isolation:**
  - All valves closed
  - Lines isolated and dismantled
  - Nearby equipment decompressed

Installing the workover unit (or servicing unit)

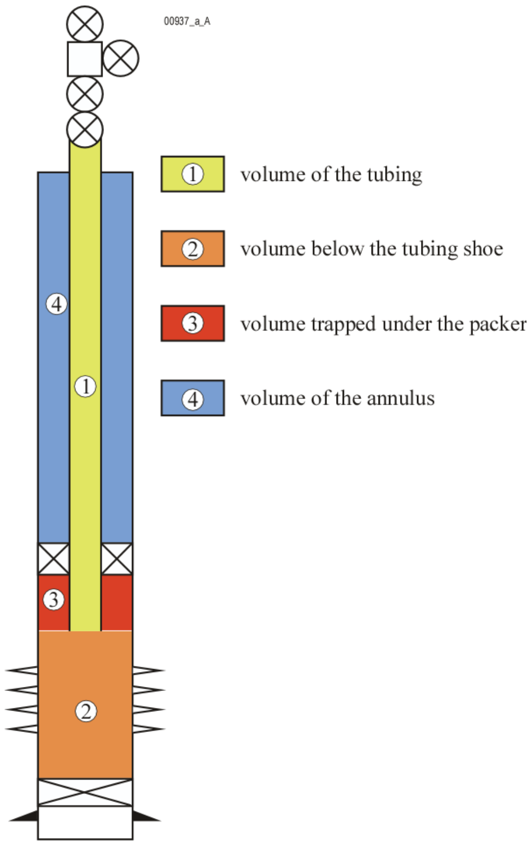
- **Followed by the set up and testing of pumping and return lines**
- **Christmas tree not yet removed to be replaced by the BOPs**

Neutralising the well

For more information, refer to the appendix "Considerations on neutralising the well"

- **Workover fluid:**
  - Fluid type: brine, ...
  - Specific gravity to have a safety margin of 5 to 15 bar *(75 to 200 psi)*
- **Volume concerned = Global volume***

Neutralising the well: Volumes involved = Global volume



Neutralising the well (cont.)

▶ Displacing the fluid:

- Circulating:
  - As deep as possible
  - With choke adjustment on the return to keep $P_{BH} > P_R$ (if no downhole plug in place)
- Squeezing:
  - Field of application:
    - Circulating method "impossible" or "not adapted" (holes in the tubing; wireline not possible:collapsed tubing, fish; etc.)
    - Very good injectivity
  - Procedure:
    - Injectivity test
    - Squeeze itself
- Mind out: at this step neutralisation is only partial

Neutralising the well (cont.)

▶ Observing the well:

- No more wellhead pressure
- Stable level
- No gas cutting (bubbles, etc.)

▶ Final neutralisation phase:

- Concerned volume:
  - Volume trapped under the packer

  And possibly:
  - Tubing & annulus volume below the circulating device
    Or
    Annulus volume
- To be done as soon as feasible once the Xmas tree has been replaced by the BOPs

Replacing the Xmas tree with the BOPs

- **Safety barriers:**
  - On the tubing side:
    - Workover fluid
    - Downhole plug, SCSSV, BPV
  - On the annulus side:
    - Workover fluid (if circulating) or annulus fluid (if squeezing; in this case, constitute an actual safety barrier or not, depending on its specific gravity)
    - Packer, tubing hanger
- **As quickly as possible:**
  - Personnel mobilised
  - Equipment ready
  - Appropriate handling & hoisting equipment available
  - Wellhead bolts checked, etc.
- **Followed by a BOPs test**

Removing completion equipment

- **Tubing safety device on the rig floor**
- **Procedure function of:**
  - The type of equipment & its condition*
- **In the program, provide alternatives in case of operating difficulties**
- **Circulate as soon as possible the volume trapped under the packer**
- **Check the well's stability during all the job:**
  - Take care to avoid swabbing (particularly when pulling out the packer)
  - Keep the well full & compare the filling volume with the pulled out steel volume

Examples of procedure for removing completion equipment

Retrievable packer	Permanent packer
▶ **Packer unsetting**(*) ▶ **Pulling out slowly and:** • Checking levels (trip tank) • Filling up every 10 stands of pipe (if no trip tank) • Beware of swabbing **(*) If unsetting failed:** • Cutting tubing • Pulling out tubing • 1/2 safety joint running in • Packer washover • Packer fishing and pulling out	▶ **Locator picking up or tubing anchor unlatching or tubing cutting** ▶ **Pulling out slowly and:** • Checking levels (trip tank) • Filling up every 10 stands of pipe (if no trip tank) ▶ **Packer milling tool running in** ▶ **Milling out** ▶ **Packer pulling out, slowly and :** • Checking levels (trip tank) • Filling up every 10 stands of pipe (if no trip tank)

Downhole operations

- **Bottom hole checking with:**
  - A drill bit and/or a scrapper
- **Possibly:**
  - Screen washing over
  - Drilling out (sediment, bridge plug, well deepening)
  - Cement job evaluating, logging
  - Remedial cementing
  - Perforation plugging
  - Cement plug or bridge plug setting
  - Pressure testing
  - Perforating, reperforating
  - Etc.

Recompleting the well

- **Running in completion equipment**
- **Replacing the BOPs by the Xmas tree**
- **Well start up**
- **Moving out the servicing or workover unit**
  - After (or before) the well start-up
  - Safety barriers in place

Basic problems on workover on depleted reservoirs

- **Losses and/or formation damage during the workover**
- **Kick-off after workover:**
  - All the more difficult since the losses are great

Losses and/or formation damage: Main solutions

- **"Light" workover fluid:**
  - Oil base fluids, diesel (SG > 0.8)
  - Foam (SG < 0.2)

  But: - between these?

  - mind the specific gravity of the annular fluid
- **"Temporary" blocking agents:**
  - Unstable with temperature

  Or
  - Highly soluble in acid

  But: never 100 % destructible

Losses and/or formation damage: Main solutions (cont.)

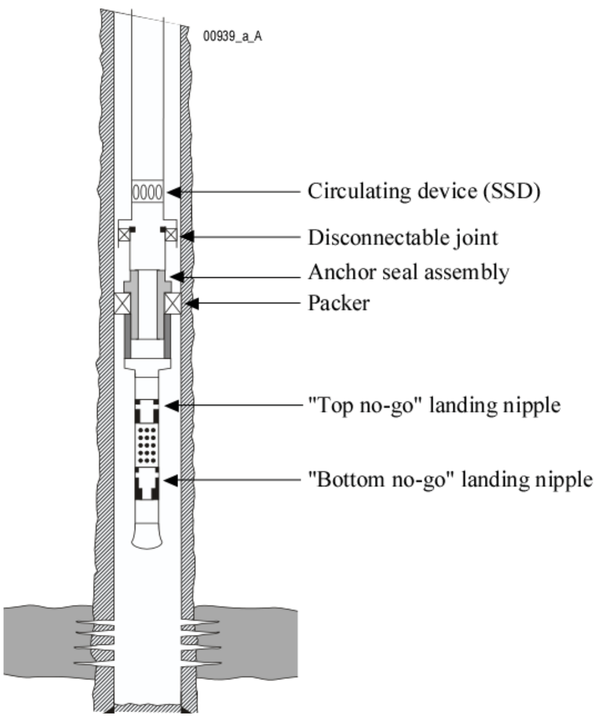
- **Working with a "lost" level:**
  - Level not at surface but monitored
  - Monitoring:
    - Level checking: (wireline), echometry

    Or
    - Filling flowrate
  - But: may lead to huge losses and consequently to formation damage and kick-off problems

Losses and/or formation damage: Main solutions (cont.)

- **Suited downhole equipment***
  (if the intervention concerned only the equipment above the packer)
- **Work on a live well*:**
  - Coiled tubing
  - Snubbing

Downhole equipment suited to depleted reservoir: Example of equipment & Procedure for pulling out the tubing



1. **A plug is set in the landing nipple of the fixed part of the disconnectable joint (beforehand a plug can also be set in the top no-go landing nipple)**
2. **The circulating device is opened or the production string is perforated just above the disconnectable joint**
3. **The workover fluid is circulated into the well**
4. **A BPV is set in the tubing hanger**
5. **The Christmas tree is removed**
6. **The BOPs are installed**
7. **The BPV is replaced by a TWCV**
8. **The BOPs are tested (between the TWCV and the blind rams) ; a tubing is screwed into the tubing hanger and the pipe-ram BOPs are tested against on the tubing**
9. **The tubing hanger is unlocked (tie-down screws)**
10. **The upper part of the production string is pulled out**

Work on a live well in case of a depleted reservoir

Coiled tubing

Snubbing

Kick-off after the workover

- No problem if the aim of the workover was to "install" an artificial lift system
- Coiled tubing & nitrogen
- Swabbing, rocking, etc.

Causes of fishing operation

- Retrievable packer which cannot be unset
- Stuck packer
- Broken tubing
- Unscrew string
- Stuck string
- Cemented string
- Etc.